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Arizona Corporation Commission
DOCKETED
MAY 9 - 2019
DOCKETED BY

May 9, 2019

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

RE: Arizona Public Service Company (APS or Company)
Inquiry into Role of Forest Bioenergy, Docket No. E-00000Q-17-0138

On March 20, 2019, APS submitted a letter to inform the Commission, and other interested parties, that it intended to file a report summarizing the results of an evaluation of the feasibility and potential cost of converting a unit at our Cholla power plant to burn biomass.

Please find attached the results of that evaluation, entitled *Biomass Conversion of the Existing Cholla #1 Facility*.

APS is available to answer questions or provide additional information.

Sincerely,

Barbara D Lockwood

Barbara D. Lockwood
BL/kac

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AZ CORP COMMISSION
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c: Chairman Bob Burns
Commissioner Andy Tobin
Commissioner Boyd Dunn
Commissioner Sandra D. Kennedy
Commissioner Justin Olson
Elijah Abinah
Jim Armstrong
Robin Mitchell

BIOMASS CONVERSION OF THE EXISTING CHOLLA #1 FACILITY

May 2019

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EXECUTIVE SUMMARY

In May 2017, the Arizona Corporation Commission (ACC) initiated a docket that required APS to review the status and potential mitigation of forest fires in Arizona and identify solutions from a biomass generation perspective. After a number of workshops, public hearings, and a market based evaluation by APS to find potential biomass solutions, parties continued to look for a potential fix to the biomass situation.

In December 2018, the Commission adopted a policy statement regarding the role of forest bioenergy in Arizona. It suggested that biomass should be subject to a renewable energy carve-out equal to or greater than 60 MW for affected utilities. In March 2019, APS filed a letter in the Biomass Docket informing the Commission and interested parties that it was evaluating the feasibility of converting a unit at our Cholla power plant to burn biomass, and intended to file a report summarizing the results of the evaluation within 60 days.

This report updates the status of the Cholla #1 evaluation. APS retained Black & Veatch to perform technical analysis and to prepare capital and O&M cost estimates for the potential Cholla #1 biomass conversion project. APS then used that as the basis for economic analysis of the project. If the project moves forward, updated information will be provided as it becomes available. The key results and conclusions of Black & Veatch and APS Cholla biomass studies to date include the following:

- It is feasible to convert Cholla #1 to burn dried, sized woody biomass
- The converted unit could provide approximately 83 MW of net output to the grid
- The conversion could be completed as early as 2022
- Capital cost of the conversion is $205 million
- The amount of fuel available to the plant will be determined through the Forest Service RFP
- The cost of collecting and delivering biomass fuel to the plant will be determined through an APS fuel RFP

- APS assumed enough fuel would be available to run the plant at 75% capacity factor, resulting in a levelized busbar cost of 115 $/MWH
- Conversion of Cholla #1 would provide positive economic impacts to the region including jobs (construction, plant operations, biomass collection and transportation, and indirect jobs) and property taxes.

There are a number of items that need to be addressed for this project to move forward.

- APS needs to conduct a fuel RFP in parallel with the upcoming Forest Service RFP. It is important that the RFPs are coordinated to provide the most opportunities for successful outcomes.

- There needs to be sufficient response to the Forest Service RFP to support forest products industries as well as to deliver sufficient quantities of biomass to the Cholla plant at the lowest possible prices.
- Assuming sufficient quantities and acceptable prices for biomass fuel are bid to APS by creditworthy counterparties, successful bidder(s) in the APS fuel RFP must also be awarded contracts from the Forest Service.
- Preliminary engineering and environmental permitting activities must result in acceptable capital cost estimates.
- The ACC must approve the APS plan to continue developing the project and allow cost recovery of the above items through the Renewable Energy Standard and Tariff (REST).
- Participation from other Arizona utilities is needed to provide an equitable cost-sharing arrangement.

APS is diligently working with parties to address the items listed above and will keep the Commission and Staff informed of progress and timelines as additional information is available.

INTRODUCTION

ACC Biomass Policy

In May of 2017, Commissioner Dunn of the ACC requested the opening of a docket[1] to explore the role of forest bioenergy in Arizona as a means to use the woody biomass generated from public lands and other land ownerships to create energy for the grid. Many stakeholders, including APS, have participated in a number of workshops and public meetings and have provided input to the Commission. As a part of that process, APS filed "APS Forest Bioenergy Report, November 2017" with the Commission[2]. In that effort, APS retained Black & Veatch to perform a forest resource assessment, and estimate the cost of constructing new biomass facilities in Northern Arizona.

In December 2018, the Commission adopted a Policy Statement suggesting that biomass should be subject to a renewable energy carve-out equal to or greater than 60 MW for affected utilities. It also stated that the affected utilities, as defined by the REST rules, would be required to acquire their appropriate share of the 60 MW total as determined by a one-time allocation to the Affected Utilities. In February 2019, the ACC ordered all Affected Utilities subject to the Renewable Energy Standard and

[1] Docket No. E-00000Q-17-0138.
[2] Filed in compliance with Decision 76295, and in Docket E-00000Q-17-0138.

Tariff ("REST") Rules to immediately commence working with Commission Staff to develop a comprehensive plan for biomass generation to be considered as part of each Utility's REST Plan.

Many of the Commission policy goals are directly aligned with the overall purpose of the Four Forest Restoration Initiative (4FRI) - to restore the structure, pattern, composition, and health of fire-adapted ponderosa pine ecosystems, reduce fuels and the risk of unnaturally severe wildfires, and provide for wildlife and plant diversity. Toward this end, 4FRI has a goal of mechanically treating one million acres of forest in Northern Arizona over twenty years. This is expected to result in the treatment of 50,000 acres per year, and produce one million green tons of biomass in addition to the merchantable wood. One way to dispose of this large volume of biomass is to use it to produce electricity.

APS continues to be engaged with the ACC and Stakeholders in the Inquiry into the Role of Forest Bioenergy in Arizona, and shares the broader goal of encouraging responsible forest management and reducing the risk posed by wildfires to both APS's customers and the state. On March 20, 2019, APS filed a letter with the Commission stating, "In support of the Commission's policy, and to further our effort to identify potential solutions in forest bioenergy, APS has begun evaluating the feasibility and cost of converting a unit at our Cholla power plant to burn biomass." The letter informed the Commission and interested parties that it intended to file a report summarizing the results of the evaluation within the next 60 days, and if the analysis shows that the Cholla conversion is more cost-effective than other alternatives, we would propose to move forward on the project with the ACC's approval.

Cholla Unit 1 Generating Facility

Cholla Unit 1 is the smallest generating facility (116 MW net output) of four total units located at the Joseph City, Arizona power plant. Unit 1 was put into service in 1962 and will no longer be able to burn coal beyond 2025 based on Arizona's Regional Haze State Implementation Plan. The other units at the station include: Unit 2 retired in 2015, and Units 3 & 4 which are also required to cease burning coal beyond 2025. Unit 4 is owned by Pacificorp, however the entire plant is operated and maintained by APS.

The relatively small size of Cholla Unit 1 lends itself to a potential biomass conversion, and may contribute toward meeting the Commission Biomass Policy as well as helping accomplish 4FRI's goals. APS has engaged with Black & Veatch as far back as 2003 in evaluating options for burning biomass at the Cholla plant. Over the last year and a half, Black & Veatch has helped APS assess the feasibility of several options for converting Unit 1 to burn biomass, including conversion to a stoker boiler, gasification, pyrolysis-derived oil, torrefaction, and direct burning of dried, sized woody biomass. It was concluded that direct firing with dried / sized biomass offered the greatest promise to achieve stable operations, maximize biomass power generation, and manage costs.

APS recently retained Black & Veatch to develop capital and O&M cost estimates for the direct burn option, which forms the basis for this report. The Black & Veatch study is summarized herein, and a redacted[3] version is attached in the Appendix.

Industry Participation/Forest Service RFP/Transportation of Fuel

The United States Forest Service (USFS) is in the process of preparing an RFP to accomplish the forest restoration goals discussed above. They have indicated that the RFP will be large scale, provide up to 20 year terms needed to attract forest industries, will be issued in late spring or early summer, and expect to award contracts by the end of the year. APS believes that concurrent release of the USFS RFP and an APS fuel supply RFP will increase the opportunities for both the Forest Service and APS. For planning purposes, APS assumes the RFP will be released in June 2019.

Once the RFP is released, contractors may bid on merchantable wood that would be supplied to forest products industries such as sawmills or other wood product industries, and could also submit bids to APS in a parallel RFP process to deliver chipped biomass to the Cholla power plant. Potential contracts with APS may play a role in the Forest Service decisions on contract awards. Ultimately it will be up to

[3] Portions of the report related to critical infrastructure information were redacted as they are considered to be sensitive from a security standpoint.

the Forest Service to select the most effective solutions which may or may not involve the Cholla conversion project.

Project Structure/Alignment of Utilities

If the Cholla conversion project moves forward, APS intends to own, or co-own, and operate the power plant, acquire the fuel from successful contractors in the Forest Service RFP, and deliver a portion of the output to other Arizona utilities. APS does not intend to be in the business of collecting and transporting the biomass fuel.

CHOLLA UNIT 1 BIOMASS CONVERSION COST ANALYSIS

APS retained Black & Veatch to perform technical studies related to the conversion of Cholla #1 to burn biomass. They determined that the conversion to burn dried sized woody biomass along with a limited amount of natural gas co-firing, which is necessary for stable boiler operation, was the most feasible alternative. Information derived from those studies was used to develop a levelized cost of electricity (LCOE) estimate discussed in this section. Details of the conversion, including capital and operation and maintenance costs estimates are summarized in the last section of this report.

Capital

The capital cost estimate prepared by Black & Veatch indicated the overnight (in 2019 dollars) investment cost to convert Cholla #1 to biomass would be approximately $135 million. This accuracy of the estimate is +40% / -15%, meaning it could cost between $115 and $189 million. For the purposes of this economic analysis, APS chose the higher end of the range (+35%, since estimate already included some contingency), added escalation and AFUDC to arrive at a total installed cost of $205 million[4]. If authorized to proceed with the project, APS expects that preliminary engineering and environmental permitting work would improve the cost estimate and accuracy by the end of 2019.

Fuel

The resource assessment performed by Black & Veatch discussed above indicates a wide range of possible fuel costs for biomass delivered to the Cholla plant by contractors. The main driver in determining fuel cost is the distance the chipped biomass has to be transported from the 4FRI district to the plant. Black & Veatch calculated the road-mile distance from the centroid of each district, the

[4] Cost excludes construction overheads and remaining book value of the plant, which are sunk or allocated costs, and do not represent actual incremental costs of the project. They will be considered for ratemaking purposes.

amount of biomass potentially available from each district, and provided ranges for both collection costs ($/ton) and transportation costs ($/ton-mile). For this analysis, APS used the midpoint of the collection and transportation costs, weighted by the amount available from each district, resulting in a delivered cost of 52 $/bone-dry ton (2017$), and escalated at the assumed rate of inflation (2.5% per year). Based on the range provided by Black & Veatch, the fuel cost could potentially be between 37 and 67 $/bone-dry ton. Actual costs and volumes may be determined through a competitive RFP process conducted in the second half of 2019 with the intention of driving costs lower.

O&M

Black & Veatch estimated the O&M cost by reviewing historic costs, and adjusting for differences between coal and biomass operation. They provided a total non-fuel O&M cost of $10,694,000 per year, comprised of $4,404,000 variable O&M[5] and of $6,290,000 fixed O&M.

Capacity Factor

Capacity factor will be largely determined by fuel availability derived through the RFP. Given that the Cholla conversion would provide nearly 40% more capacity than proposed in the policy statement, it is expected that could result in proportionally lower capacity factors while enabling an equivalent amount of forest restoration. This study assumes range of 60% to 85%, with an average capacity factor of 75%.

Schedule

The Black & Veatch report indicated that it would take 32 months from Notice to Proceed (NTP) to commercial operation of the plant. Assuming NTP in 2019, environmental permitting and preliminary engineering would need to be initiated immediately with commercial operation projected as early as 2022. Additional details are provided on the schedule in the last section of this report.

[5] Based on an assumed capacity factor of 85%.

Levelized Cost of Energy (LCOE)

Table 1 below summarizes the inputs to the Levelized Cost of Electricity calculation.

Table 1 – Inputs to Levelized Cost of Electricity (LCOE)

ASSUMPTION	VALUE
Capacity (MW)	83.2
Capital Cost ($Million)[6]	205
Biomass Fuel Cost ($/bone-dry ton)[7]	59
Natural Gas Cost ($/MMBtu)	2.48
Heat Rate (Btu/kWh)	12,700
Fixed O&M ($/kW-yr)	81.4
Variable O&M ($/MWH)	8.06
Capacity Factor	60% - 75% - 85%
Discount Rate[8]	7.57%
Inflation Rate	2.5%
Book Life (Years)	20
Tax Life (Years)	5

[6] High end of the Black & Veatch cost range, and includes escalation and AFUDC.
[7] Fuel cost in 2022 dollars.
[8] After tax weighted average cost of capital.

Based on the above inputs, the Levelized Cost of Electricity is shown in Table 2 below.

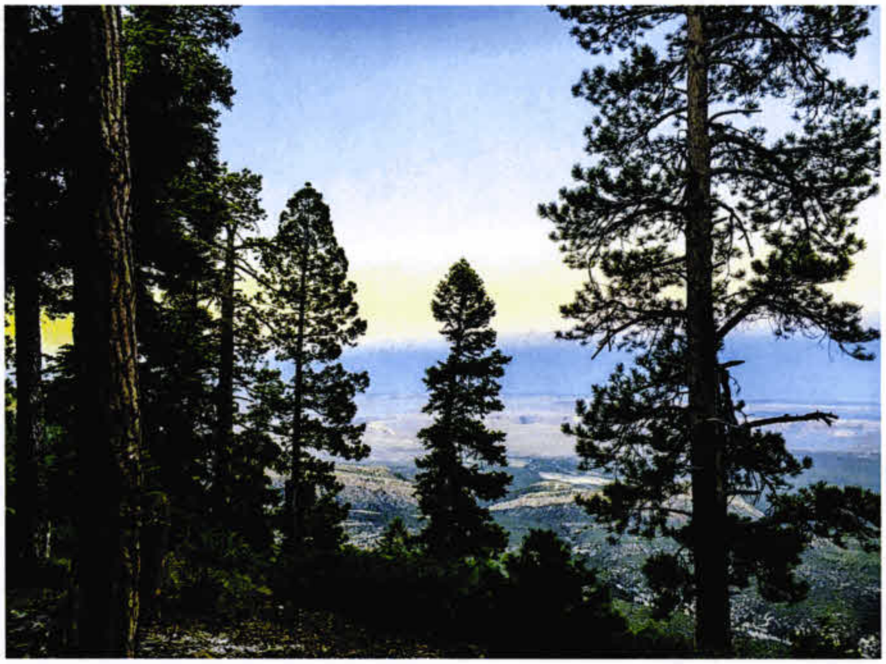
Table 2 - Levelized Cost of Electricity ($/MWH)

COST ITEM	LOW CAPACITY FACTOR (60%)	BASE CAPACITY FACTOR (75%)	HIGH CAPACITY FACTOR (85%)
Capital	50	**40**	35
Fuel	50	**50**	50
O&M	28	**25**	23
Total	128	**115**	108

IMPACTS

Forest Restoration

In its November 2017 filing with the ACC, APS discussed the benefits that forest bioenergy projects may produce, including wildfire mitigation, watershed improvement, forest industry support, and other positive environmental externalities. Those benefits are important, are incorporated by reference, but not evaluated further as part of this analysis. However, the amounts of forest restoration potentially facilitated by the Cholla #1 conversion are discussed below.



At full load operation, the plant would consume about 53 bone-dry tons per hour, and at the assumed capacity factor of 75%, that would translate to about 578,000 wet tons per year. The biomass yield from the forest can be between 10 and 30 tons per acre, so the amount of acres could vary from one year to another depending on the density of the landscape being cleared. Based on an assumed average density of 20 tons per acre, 29,000 acres per year of forest restoration could support 75% capacity factor operation of Cholla #1. The following table shows the relationship between acres of forest restoration, green tons of biomass material, and plant capacity factor.

Table 3 - Forest Restoration Assumptions

FOREST RESTORATION (ACRES/YEAR)	BIOMASS (GREEN TONS[9])	CHOLLA #1 CAPACITY FACTOR
23,000	463,000	60%
29,000	**578,000**	**75%**
33,000	655,000	85%

Operational

Due to increasing amounts of noncurtailable rooftop solar generation on APS system as well as in the region, it is becoming increasingly challenging to operate power plants in baseload mode. With Cholla #1 being larger than proposed by Commission policy, it should have some operational ability to mitigate baseload impacts. It can burn the desired amount of biomass, and run at reduced load or be turned off during low customer load/high renewable generation hours, and also run at higher load in the summer when the generation is needed to meet peak loads.

Infrastructure

The Cholla plant has existing infrastructure in place to support biomass generation. First of all, the boiler and turbine generator, which would otherwise cease operation in 2025, can continue to be used to produce electricity for years to come. It also has sufficient transmission and water availability, and the plant is also located on Interstate 40, which could potentially reduce the cost of fuel transportation. All of these factors may provide economic benefits compared to other potential projects.

Customer Cost

Compared to other biomass electric generation alternatives considered, the conversion of Cholla #1 is likely to have less impact on customer bills. While it is more expensive than conventional generation and other renewable generation, it appears to be the most cost-effective way for APS and other utilities to comply with the ACC's biomass policy. Table 4 below shows the expected cost of biomass relative to projected average system costs based on the amount of biomass fuel acquired through the Forest Service RFP process.

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[9] Based on 40% moisture content.

Table 4 - Customer Cost of Biomass Generation

	463,000 GREEN TONS/YEAR	578,000 GREEN TONS/YEAR	655,000 GREEN TONS/YEAR
Generation (MWH)[10]	437,000	547,000	620,000
Generation Cost ($/MWH)	128	115	108
Market Value ($/MWH)	43	39	35
Above Market Cost ($/MWH)	85	76	73
Above Market Cost ($Millions/Year)[11]	37	41	45

Local Communities

Continued operation of Cholla #1 would have positive impacts in the local communities for property taxes, and jobs related to construction activities, personnel needed to operate the facility, logging/gathering and transportation of the biomass, and indirect effects due to the economic stimulation of the increased population and resources required to support the fuels reduction process.

Black & Veatch estimated that it would take 32 people to operate the Cholla #1 biomass conversion. In their November, 2017 report, they also estimated the logging industry and indirect job impacts based on studies performed by investigators at Northern Arizona University. Job impacts related to the Cholla #1 conversion would be similar to the impacts reported for the Medium Scenario. In addition to the operations jobs at the plant, there could be another 90 direct (logging/transportation) and 16 indirect permanent jobs plus another 800 direct and 600 indirect temporary construction jobs.

Water Consumption

Cooling water requirements are marginally higher for biomass than they are for coal on a gallons/MWH basis, however since the plant rating will be decreased, the actual quantity of cooling water for full load operation of biomass will be approximately 20% lower than for coal. APS uses well water to cool the plant, and has sufficient water rights for continued operation of the unit.

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[10] Generation is reported for 100% of the project.

[11] Above market cost is reported for APS customers, 63% of the total.

Emissions

Emission rates of criteria pollutants will be determined during the preliminary engineering and environmental permitting processes. Appropriate emission controls will ensure that the unit meets applicable environmental standards.

It is important to note that woody biomass contains less sulfur and ash than coal fuel. Black & Veatch boiler modeling results indicate improved performance for SO_2, NOx, and opacity.

Biomass is considered carbon neutral in Arizona's Renewable Energy Standard and Tariff (REST) rules. Natural gas co-firing will produce a small amount of CO_2 emissions, approximately 175 lb/MWH[12].

ENVIRONMENTAL AND PERMITTING

APS conducted a desktop permitting review of the proposed conversion of Cholla Unit #1 from coal to a combination of woody biomass and natural gas. The objective was to determine the ability of the existing air pollution controls to meet the applicable environmental and regulatory requirements, and to identify potential studies and authorizations that APS would need to complete such a proposed project.

It was concluded that it is possible to permit the proposed project through modifications to Cholla's existing air quality, storm water and aquifer protection permit permits. The air quality permit modification is the most complicated permit to obtain and must be completed prior to any physical modifications to Unit #1. The most significant risks that were identified included the type of air quality permit modification that is required to be obtained, and the potential for cost impacts due to the additional air pollution controls that are either not planned for future operation (tower absorber) or do not currently exist at the facility. These risks are driven primarily by commitments APS made as a result of Regional Haze reduction plans, but could be mitigated or eliminated based on the performance of certain studies.

Assuming that the worst case scenario of permitting the modification to Unit #1 as a brand new facility will also follow the longest lead times, the permit modification required to start physical construction of the changes will likely be issued approximately 15 months after the selection of a contractor to complete the required studies and permit applications.

[12] For reference, coal produces approximately 2,000 lb/MWH, and natural gas combined cycle produces approximately 900 lb/MWH.

ALIGNMENT AND COORDINATION

There are many factors that need to be aligned in order for APS to complete the Cholla #1 biomass conversion project. These factors are discussed below.

Arizona Corporation Commission Approval

Although the ACC has adopted a biomass policy statement, it is not yet gone through the rule-making process. It is not known when or if a rule will be finalized, and whether it may be different than the policy. Since the cost of producing biomass electricity is above the market cost of electricity and other forms of renewable energy, APS must have the approval of the Commission to proceed with this project. Proceeding without Commission approval could risk an adverse prudency determination and limit cost recovery when the unit goes into service.

Coordination with Forest Service RFP

APS needs to align the release of its fuel RFP with the Forest Service RFP to maximize opportunities for the Forest Service RFP and to provide an adequate fuel supply to operate the biomass power plant. While it is possible that the Forest Service could accomplish its forest restoration goals without a biomass power plant(s), provision of a willing buyer for the biomass should significantly increase participation in the RFP. Without the Forest Service RFP, APS would not have a mechanism to acquire the needed fuel supply for its plant. Therefore it is essential that the Forest Service RFP and an APS fuel supply RFP proceed in parallel in terms of the solicitation dates and the bid due dates.

Confirmation of Fuel Source Supply

Assuming that APS issues a fuel RFP in parallel with the Forest Service, it should receive an initial indication of whether there is enough fuel bid to provide an adequate supply of biomass when bids are received in mid to late summer. Lower supplies of fuel result in increased costs of electricity as indicated in Table 2. APS anticipates that it needs enough fuel to operate at a minimum capacity factor of 60%. With lower amounts of fuel availability, it may be more economic to pursue other biomass alternatives with lower capacity ratings and higher capacity factors.

Fuel Contract Awards

It is expected that the Forest Service could receive bids related to a variety of uses, including forest products industries, biomass electric generation power plant(s), and other alternatives for disposal of biomass. Contract awards (amounts, timing, terms) are the within the sole discretion of the Forest Service. If Forest Service awards contracts to the same contractors who bid biomass supplies to APS, those contractors meet APS credit requirements, and APS can successfully execute contracts at the lowest possible prices, then such projects may move forward to a final Cholla evaluation.

Updated Capital Cost

APS intends to be engaged in preliminary engineering throughout 2019, refining equipment needs, schedules and cost estimates. The accuracy of the current cost estimate is +40% / -15%. Preliminary engineering will increase the accuracy and narrow the range. If preliminary engineering turns up any major challenges, and the cost to convert Cholla #1 to biomass operation increases significantly, APS and the ACC may reconsider whether or not to proceed with the project.

Participation with Arizona Utilities

APS believes that the cost of forest restoration is a state and federal issue and the cost should not be borne solely by APS customers. In order to proceed, an equitable mechanism must be in place to share costs across other stakeholders. It is APS intent to utilize approximately 63% of the output of the Cholla #1 biomass conversion on behalf of its customers, with the remaining output taken by other Arizona utilities.

SUMMARY OF BLACK & VEATCH REPORT:
CHOLLA UNIT 1 BIOMASS REPOWERING CONCEPTUAL DESIGN REPORT

Objective

APS retained Black & Veatch to develop capital and operations and maintenance (O&M) cost estimates for the Cholla Unit 1 repowering scenario in which dried / sized woody biomass is co-fired with approximately 125 million British Thermal Units (MMBtu) per hour of natural gas. Prior analysis by Black & Veatch indicated that stable operations up to 90 MW gross could be achieved using biomass with 15 percent moisture content. In order to develop these cost estimates, the following tasks have been undertaken:

- Data request and site visit to gather information needed for the analysis.
- Establishment of a conceptual design basis.
- Production of conceptual engineering documentation, including process flow diagram (PFD), equipment list, site plan, electrical load list / one-line diagram, control system philosophy.
- Formulation of an engineering procurement construction (EPC) schedule.
- Develop EPC capital and O&M cost estimates based on conceptual design.

Design Basis

Black & Veatch developed the design basis to be used in engineering and design activities for the Cholla #1 repowering project.

Feedstock

Woody biomass feedstock is to be delivered to Cholla and processed on-site for delivery to the boiler. It is based on Ponderosa Pine materials chipped in the field, and fed into the dryer at a mass flow rate of 150,911 lb/hour @ 30% moisture content.

New Bulk Material Handling Equipment

Converting the unit from burning coal to a woody biomass requires a completely new processing and handling system for the fuel. The new fuel handling system would be located in the current coal yard, and would include dumpers, hoppers, conveyors, a dryer, hogs, hammermills etc. It would have a short term storage capacity of 5 days of fuel at full load operation, and 28 days of long term storage until Unit's 3 and 4 cease operations, at which time long term storage could be expanded to 71 days. The woody biomass chips would be received at 3-1/2" x 3-1/2" x ¾" and reduce to 0.2" before being fed into the boiler. Black & Veatch obtained budgetary quotes from vendors for this equipment.

Boiler and Air Quality Control Modifications

The combustion system of the boiler will be upgraded from pulverized coal (PC) to co-firing milled and dried biomass with natural gas. It is expected that the natural gas firing system can utilize the placement of the existing ignitors and warm-up guns, with new burners and supply piping around the boiler being installed for a larger capacity.

Unit 1 air quality control system (AQCS) is currently equipped with a fabric filter for particulate removal, a wet flue gas desulfurization (FGD) system for sulfur dioxide removal, and a powdered activated carbon (PAC) injection system for mercury removal.

The fabric filters should continue to function adequately following the fuel conversion, and may require a mechanical dust collector to prevent embers from entering and damaging the fabric filters (included in cost estimate).

Given the lower sulfur content present in biomass and gas compared with coal, the wet FGD may no longer be required following the conversion. Therefore, the cost and performance estimates herein have assumed the wet FGD will be decommissioned and abandoned in place. The plant is expected to save on auxiliary power, spray water, and reagent consumption that is currently utilized for operation of the wet FGD following the conversion.

It is also expected that operation of the PAC system will no longer be required following the fuel conversion as the new fuel has no mercury content. The PAC system will be decommissioned and abandoned in place.

Nitrogen oxide (NOx) emissions may change following the biomass conversion and will depend on the specific Vendor burner design, stoichiometry, furnace temperature profile, and several other factors. NOx mitigation will need to be reviewed during detailed design when more information is available concerning the NOx emissions and permit requirements. A selective noncatalytic reduction (SNCR) system has been included in the cost estimate for conservatism based on the new combustion system modifications.

Utility Requirements

The new natural gas flow rate to the Unit 1 boiler after repowering of the unit will be based on an energy input rate of 125 MMBTU/hr and is expected to be delivered to the 32 existing natural gas burners located in the windbox assemblies at the four corners of the boiler (including coal burner ignitors, warming guns, and warming gun ignitors). The sizing for the existing high and medium pressure natural gas piping systems are assumed to be adequate. The existing low-pressure natural gas piping is undersized, and would need to be replaced.

New fire protection measures will be required for the wood processing equipment in the yard up to the existing coal silos east of the Unit 1 boiler. It is assumed no fire protection changes are required within the Unit 1 powerhouse and that the biomass surge bins, hoppers, etc. will be supplied with their own deflagration venting provisions. The wood processing equipment in the yard requires the addition of two 3,500-gpm fire water pumps and two redundant 420,000-gallon fire water tanks for fire protection. An underground fire water loop comprised of ductile iron pipe, hydrants, and above ground valve houses is anticipated in the coal yard. Deluge systems will be supplied for the biomass conveyors, as well as dust collector pre-action spray systems.

A carbon dioxide (CO2) fire suppression system will supply CO2 to the various bins, silos, and hoppers where the wood fuel is expected to accumulate and have significant residence time. The system is comprised of a new 3.5-ton CO2 tank, refrigeration unit, vaporizer skid, and supply piping.

Electrical Loads

Black & Veatch developed an electrical load list by major electrical equipment. Total power (in kilovolt-amperes or kVA) is developed for each major system. Taking into account duty cycles, the total parasitic load for new equipment is estimated to be 2,560 kilowatts (kW) while the parasitic load savings from equipment that is no longer needed is estimated at 2,390 kW. This indicates that the net parasitic load is 6,650 kW, which yields a net power generation of 83.2 MW exported to the grid.

Summary of Boiler Performance

Black & Veatch previously performed boiler modeling using EPRI's VISTA software to determine how the unit would perform using a blend of natural gas (125 MMBtu/hour) and dried woody biomass. The model was calibrated using performance data from coal operations. It was determined that, with the limited amount of natural gas, the unit could achieve stable operation at 75% load.

Black & Veatch also performed turbine modeling to confirm that the lower steam temperatures associated with biomass firing would not result in condensation on the turbine blades. They concluded that biomass firing would be operating within the limit of turbine operating conditions and impose no risk of operating the turbine at these conditions.

Control System Approach

Budgetary pricing on the wood handling equipment was solicited from various suppliers. As part of this budgetary request for pricing, the equipment vendors were requested to provide pricing for a Programmable Logic Controller (PLC) based control system for the equipment to be supplied as part of the wood handling equipment scope of supply. Therefore, control system costs for the wood yard equipment are included in the overall budgetary pricing received from the wood yard equipment vendors.

With the removal of the coal yard control system and the addition of the new wood yard PLCs interlocks to, and demand signals from, the existing boiler control system will be required. Budgetary pricing for modification to the existing boiler control system to accommodate supervisory control of the new wood handling equipment has been provided as part of the EPC cost estimate.

Schedule

A preliminary Level-1 EPC schedule for the Cholla Unit #1 Biomass Repowering project is shown in Table 6 below. Key milestone dates for major events as part of the execution of this project are listed in the table in months after notice to proceed (NTP) through commercial operating date (COD). It is expected that Cholla Unit #1 would be out of service for 10 to 12 months during construction, depending on site work requirements for new equipment. Furthermore, based on the design presented in this report, it is expected that Cholla Units #3 and #4 could remain in operation during the biomass repowering construction and operation of Unit #1. Based on this schedule, it is assumed that the conversion could be completed and achieve commercial operation in 2022.

Table 5 - Key Milestone Dates

PROJECT MILESTONE	DATE AFTER NTP
Preliminary Engineering	3 months
Permitting (Major Modification)	16 months
Detailed Engineering	22 months
Procurement	22 months
Construction	29.5 months
Commissioning and Testing Completion	32 months
Commercial Operating Date	32 months

Project Cost Estimates

Black & Veatch prepared a conceptual capital cost estimate that is classified as an American Association of Cost Engineers (AACE) Class Four estimate with an accuracy of +40 percent to -15 percent. Furnish and erect packages and equipment material prices were primarily estimated using vendor budgetary quotations for the material handling and drying systems. The balance of equipment was estimated using in-house pricing based on historical project data. All costs are expressed in first quarter 2019 US dollars (USD).

Engineering and Construction

All labor costs have been adjusted to reflect Arizona rates and productivity. The costs reflect an EPC execution approach. Engineering has been included at ten percent of total direct costs plus subcontractor indirects. Similarly, construction management costs are estimated at six percent of total direct costs plus subcontractor indirects based on the EPC schedule.

Indirects and Exclusions

The capital cost estimate represents an overnight cost with no provisions for escalation. A contractor's contingency of 20 percent of the total installed cost (TIC) is carried. General liability and builder's all-risk insurance is estimated as a percentage of TIC. An EPC contractor's fee of seven percent is also included. Exclusions from this cost estimate include permitting, capital spares, taxes / duties, liability insurance, letters of credit / bonds, tariff impacts, hazardous materials handling / abatement, and other Owner's costs.

EPC Capital Cost Estimate

A summary of the capital cost estimate is shown in Table 3-2 with the full cost estimate basis and detailed capital cost estimate attached in Appendix G of the attached Black & Veatch report. The total capital cost for the project is estimated at $134,567,000.

Operations and Maintenance Cost Estimate

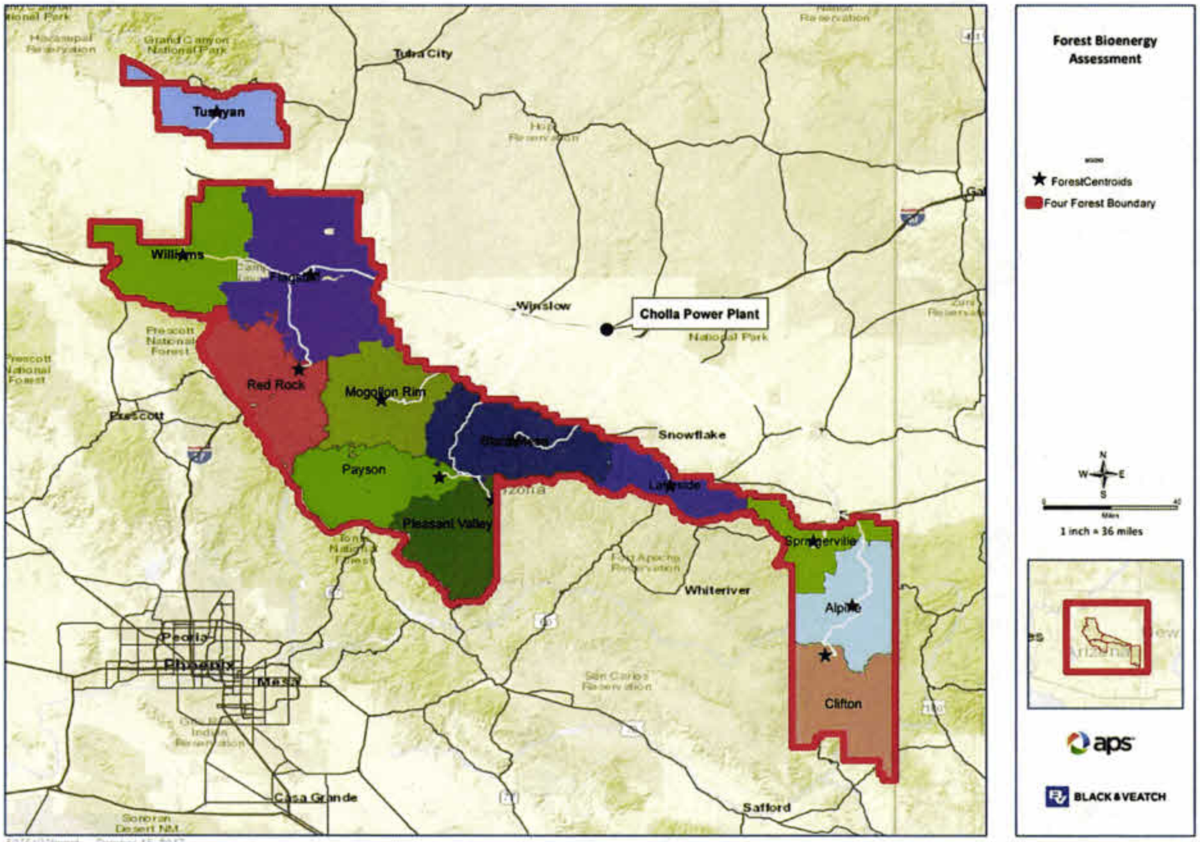
The estimated annual non-fuel O&M costs were developed. All variable expenses, with the exception of consumables and mobile equipment, were scaled and adjusted based on actual O&M data on coal plant operations provided by APS and differences in USD/MWh for coal versus biomass operations. Consumables were estimated based on expected adjusted chemical consumption using biomass fuel and excluding AQCS systems that will no longer be in use. Mobile equipment expense is estimated based on Black & Veatch experience and includes fuel.

All fixed expenses were estimated using actual O&M data provided by APS. Labor expenses were calculated assuming 28 personnel working in the Unit #1 powerhouse and four personnel working in the fuel yard. Contingencies for both variable and fixed O&M expenses were estimated assuming five percent of all other costs in each category. The total annual non-fuel O&M cost is estimated at $10,694,000 per year.

Fuel Cost Estimate

Black & Veatch has estimated delivered biomass fuel costs for APS in prior studies. In the November 2017 report, they indicated that harvesting costs were estimated based on detailed 4FRI planning, preparation, administration, and operational costs for restoration activities. These costs were updated for inflation where appropriate. Transportation costs (in dollars per green tons per mile) were estimated based on interviews with local logging companies who are operating within the 4FRI region. They also estimated the cost to collect and transport biomass from each of the 4FRI districts to the Cholla power plant by determining the distance from the centroid of each district to the plant, weighted by the amount of biomass expected to be available from each district. This resulted in a weighted average cost of 52 $/bone-dry ton in 2017 dollars. Figure 1 shows a map of the districts and the location of the Cholla power plant.

Figure 1- Map of 4FRI Districts and Cholla Location



Conclusions

In the current study, Black & Veatch offered the following conclusions.

- A more detailed design should be developed to confirm the various assumptions that were used as the basis for this study and formulate the basis for permit applications.
- APS may consider an alternative execution strategy to the proposed EPC-based approach to further explore financial costs and risks associated with the repowering option for Cholla Unit #1.

APPENDIX

Cholla Unit 1 Biomass Repowering Conceptual Design Report

Black & Veatch April 26, 2019

FINAL

CHOLLA UNIT 1 BIOMASS REPOWERING CONCEPTUAL DESIGN REPORT

B&V PROJECT NO. 401613
B&V FILE NO. 40.6200

PREPARED FOR

Arizona Public Service Company

26 APRIL 2019

BLACK & VEATCH

NOT TO BE USED FOR CONSTRUCTION

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Executive Summary

Arizona Public Service Company (APS) and Black & Veatch have been working together since 2017 to address the need for greater amounts of forestry-derived bioenergy production in the state of Arizona. APS has been a major owner/operator of the coal fueled Cholla Power Plant located in Joseph City, Arizona and is interested in evaluating whether Cholla Unit 1 can be repowered using ponderosa pine woody biomass harvested via the Four Forest Restoration Initiative. APS enlisted Black & Veatch support to develop a conceptual design for the Cholla Unit 1 Biomass Repowering Project, estimate capital and operating costs, and support the APS economic evaluation of this option.

After requesting the required information from APS and Cholla personnel, Black & Veatch developed a design basis memorandum to guide the conceptual engineering process. This document outlined the key site- and discipline-specific design criteria needed to define the system at this early stage of design. Prior analysis determined that co-firing 125 dekatherms per hour of natural gas with dried, sized wood fuel resulted in stable operations up to 75 percent rated load (90 megawatts [MW] gross). Using new bulk material handling equipment, incoming wood would be milled to a maximum 0.2-inch size and dried to 15 percent moisture before it is conveyed to the existing coal mills, which would be modified/by-passed to facilitate wood fuel delivery into the boiler. The air quality control system would also be modified, and it is envisioned that existing sulfur and mercury handling equipment could be abandoned in place; new mechanical dust collector and nitrogen oxide mitigation systems would be installed. Finally, ash handling would be converted from the existing wet ash pond system to a submerged flight conveyor bottom ash handling and disposal approach.

A variety of preliminary engineering deliverables were prepared to document the new equipment additions, modified equipment, and balance-of-plant (BOP) systems needed to facilitate the biomass repowering system architecture. These deliverables include a process flow diagram, equipment list, general arrangement drawing, and electrical one-line diagram. Tie-ins with existing utilities (e.g. electrical, fire water, and natural gas) were defined as well. Electrical loads were quantified and indicate that a net parasitic power of 6.65 MW would be needed to yield 83.2 MW of power for export to the grid. The plant is expected to produce this net power while consuming 151,000 pounds per hour (lb/hr) of 30 percent moisture biomass (into the dryer) and 125 million British thermal units per hour (MMBtu/hr) of natural gas, resulting in a net plant heat rate of 12,700 British thermal units per kilowatt-hour (Btu/kWh).

On the basis of the conceptual engineering design, Black & Veatch estimates that an engineering, procurement, and construction (EPC) and permitting schedule of 32 months would be needed to fully realize this project. A capital cost of $134,567,000 with +40 percent/-15 percent accuracy was estimated on the basis of budgetary vendor quotations for wood processing equipment and in-house data for boiler/air quality equipment modifications and BOP systems. The annual non-fuel operations and maintenance costs were estimated at $10,694,000 using actual costs from coal plant operations provided by APS, adjusted by Black & Veatch for the wood- and natural gas-fueled alternative.

It is recommended that APS consider conducting a more detailed design phase as soon as possible after financial viability has been demonstrated to confirm the multitude of technical assumptions used as the basis for this and prior analyses. Finally, APS should consider the most advantageous execution strategy as an alternative to the proposed EPC approach to alleviate or shift financial risks associated with the capital cost estimate presented in this report.

1.0 Introduction

1.1 BACKGROUND

1.1.1 Plant History

APS operates the coal-fired Cholla Power Plant in Joseph City, Arizona. The Cholla Power Plant Unit 1 was originally commissioned in 1962 and has a capacity of 113.6 MW. Units 2 through 4, constructed and commissioned in the late 1970s and early 1980s, have a combined capacity greater than 1,000 MW. For most of its operational life, the plant was fueled by subbituminous coal from the McKinley Mine until that mine was closed in 2009. Subsequently, Unit 2 of the plant was retired in 2016. APS, currently scheduled to cease operations on coal and close all three remaining units by 2025, is evaluating repowering Unit 1 of the plant using biomass and natural gas as fuel.

1.1.2 Project Background

In August 2017, the Arizona Corporation Commission (ACC) ordered APS to evaluate increased forest bioenergy. Black & Veatch was retained as the principal investigator to conduct a Forest Bioenergy Assessment study, for which separate reports evaluating the potential of a stand-alone biomass power plant in addition to the repowering of Cholla Unit 1 were prepared. For the original Cholla Unit 1 repowering study, Black & Veatch evaluated several options at a high level, including co-firing natural gas with gasified biomass, pyrolysis-derived oil, torrefied biomass, and wood chips by converting the suspension boiler to a Stoker boiler.

APS retained Black & Veatch once again in December 2018 to further evaluate options for repowering Cholla Unit 1 and to determine the most effective technology configuration for power production using wood derived from forest management. This 2018 abbreviated study included additional boiler and thermal performance modeling beyond the 2017 study for co-firing natural gas with gasified biomass, torrefied biomass, and dried/sized biomass in Cholla Unit 1. It was concluded that co-firing natural gas with dried/sized biomass offered the greatest promise to achieving stable operations while maximizing biomass power generation at 75 percent rated load (90 MW gross). On the basis of these conclusions, APS asked Black & Veatch to prepare a conceptual design and cost estimate for the on-site drying and sizing of biomass at Cholla to facilitate repowering of Unit 1; this is the basis for the present study.

1.2 OBJECTIVES AND ORGANIZATION

The primary objective of this project was to develop capital and operations and maintenance (O&M) cost estimates for the Cholla Unit 1 repowering scenario in which dried/sized woody biomass would be co-fired with approximately 125 MMBtu/hr of natural gas. Prior analysis by Black & Veatch indicated that stable operations up to 90 MW gross could be achieved using biomass with 15 percent moisture content. To develop these cost estimates, the following tasks were undertaken:

- Data request and site visit to gather information needed for the analysis.
- Establishment of a conceptual design basis.
- Production of conceptual engineering documentation, including process flow diagram (PFD), equipment list, site plan, electrical load list/one-line diagram, and control system philosophy.
- Formulation of an EPC schedule.

- Development of EPC capital and O&M cost estimates from the conceptual design.

Many of the engineering deliverables are included in the appendices of this report; brief narratives are included in the body of the report. Acronyms used throughout the document are included in Appendix A. This report is organized into the following sections:

- Section 2.0 – Engineering.
- Section 3.0 – Project Schedule and Cost Estimates.
- Section 4.0 – Conclusions and Recommendations.

2.0 Engineering

2.1 PLANT PERFORMANCE SUMMARY

Black & Veatch previously performed Cholla Unit 1 boiler performance modeling to determine the fuel consumption and power generation performance if the unit were to be repowered with biomass and natural gas. Table 2-1 summarizes the plant performance associated with these prior studies, as well as the fuel dryer performance-related findings associated with the conceptual design presented herein. These results are presented for both 40 percent moisture and 30 percent moisture for biomass in the forest, depending on the level of field drying that may take place (which would have an impact on the mass of fuel delivered to plant gate). In both cases, a 30 percent moisture fuel is assumed to be delivered to the dryer, which, in the 40 percent moisture case, implies that some drying occurs in chipping, transport, and storage in the fuel yard prior to delivery to the dryer.

Table 2-1 Plant Performance Summary

PERFORMANCE METRIC	40% MOISTURE IN FOREST	30% MOISTURE IN FOREST
Biomass into Dryer		
Biomass Input to Dryer (wet lb/hr)	151,000	151,000
Moisture Content into Dryer	30%	30%
Biomass Input to Dryer (dry lb/hr)	106,000	106,000
Biomass Heating Value (dry Btu/lb)	8,806	8,806
Heat Input to Dryer (MMBtu/hr)	930.24	930.24
Biomass into Boiler		
Biomass Input to Boiler (dry lb/hr)	95,000	95,000
Heat Input to Boiler (MMBtu/hr)	837.22	837.22
Biomass Harvested/Transported		
Biomass Moisture in Forest	40%	30%
Biomass Quantity from Forest (wet lb/hr)	176,000	151,000
Biomass Quantity from Forest (wet tons/hr)	88.0	75.5
Biomass + Natural Gas Repowering Performance		
Natural Gas Heat Input (MMBtu/hr)	125	125
Net Plant Output (MW)	83.2	83.2
Net Plant Heat Rate (Btu/kWh)	12,700	12,700

2.2 DESIGN BASIS

A Design Basis Memorandum was prepared to define the basis used in engineering/design activities for the Cholla Unit 1 Biomass Repowering Project (attached in Appendix B).

2.2.1 Site Information

Site-specific design criteria were developed using local weather data. It was assumed that existing water sources would continue to be used after the fuel change for cooling water makeup, fire protection, and service/potable water applications. It is expected that a new air permit will be required for the fuel change, but qualitative emissions assumptions have been made to allow for design activities. The site is located directly off Interstate 40 down a short length of frontage road. Unit 1 is located on the east side of the line of four boilers and is separated from Unit 2 by approximately 30 to 50 feet at most locations as a stand-alone unit. The existing coal yard, a significant portion of which will need to be converted over to wood handling and processing operations, is located to the north of the Unit 1 power house.

2.2.2 Feedstock

Table 2-2 shows the woody biomass feedstock to be delivered to Cholla and processed on-site for delivery to and utilization by the existing boiler.

Table 2-2 Feedstock Design Basis

PARAMETER	UNIT	PONDEROSA PINE
As received basis (AR)	Wt%	100
As fed basis (AF)	Wt%	100
Dry Basis (db)	Wt%	100
Proximate and Ultimate Analysis		
Moisture AR	Wt%	30
Moisture AF	Wt%	15
Volatile Matter	db%	83.96
Ash	db%	0.57
Fixed Carbon	db%	15.47
Carbon	db%	51.25
Hydrogen	db%	6.21
Nitrogen	db%	0.14
Oxygen	db%	41.78
Sulfur	db%	0.05
Ash	db%	0.57
Moisture	db%	15.00
Other Parameters		
Higher Heating Value, db	Btu/lb	8,806
Chlorine	db%	0.01

PARAMETER	UNIT	PONDEROSA PINE
Mass Flow (wood into dryer)		151,000 lb/hr
Feedstock Size AR		3½" x 3½" x 3/4"
Feedstock Angle of repose		45°

2.2.3 New Bulk Material Handling Equipment

Converting the unit from burning coal to a woody biomass requires a completely new processing and handling system for the fuel. A number of factors would have to be considered for this change, such as the flowability of the woody biomass compared to coal, fuel storage requirements, handling a dried fine fuel and a fuel delivery method. Woody biomass does not flow like coal and tends to plug in chute work designed for handling coal. Dried fine woody biomass poses an explosion and fire risk greater than that for coal and so the storage capacity of this processed fuel needs to be minimized. After the woody biomass is dried and milled down to 0.2 inch size, open conveyors cannot be used because dust hazards are created. Delivery by rail car is problematic with wood chips; delivery by trucks is more common, easier, and less expensive for the fuel suppliers. Although considerations were given to reusing the coal handling system as much as possible, these issues did not be accommodate that option.

The new woody biomass handling system will be broken down into two main subsystems: receiving and reclaim. The receiving subsystem will include all the receiving and storage equipment, and the reclaim subsystem will include all the reclaim, processing, and boiler feed equipment. The new receiving subsystem will receive wood chips via 113 truck trailers per day, each carrying 22.5 tons, and is designed to operate 12 hours per day and five days per week. A road loop will be provided for the trucks where they will back into the trailer unloaders, which will elevate and dump the trailers into receiving hoppers. These hoppers will be enclosed and equipped with a dust collection system. The hoppers will feed the wood chips onto a series of conveyors that will feed a circular stacker reclaimer. The circular stacker reclaimer will create a kidney-shaped pile in a 240° arc. The kidney-shaped pile will be sized for 5 days with the unit operating at full capacity. From the circular pile mobile equipment can push the fuel out to a long-term storage pile that can be sized for up to 86 days of operations. Initially, while the other coal-fired units continue to operate, the long-term storage pile will be limited to 33 days of stored wood fuel.

The new reclaim subsystem will be designed to operate on a continuous basis to match the boilers feed rate. Reclaiming from the circular pile will be done by the automated circular stacker/reclaimer. In cases where the reclaimer is out of service for maintenance, an above-grade reclaim hopper will be available to be fed by mobile equipment. The mobile equipment can reclaim from the long-term storage pile or the circular pile. Once reclaimed, the woody biomass will be processed to remove stones and metals and then screened. The oversized wood from the screen will be reduced in the hog to optimize the wood particle size for drying. After being processed the wood will be loaded into a 1 hour surge bin. This surge bin will provide the system a level flow rate into the dryer. From the surge bin the wood will be fed into a rotary drum dryer designed to reduce the wood moisture content from 30 percent to 15 percent. As the wood passes out of the dryer, approximately 10 percent of the wood will be drawn off and used as fuel for the hot gases needed in the dryer. The dryer will recycle the hot gases to increase the efficiency of the process. Downstream of the dryer the wood will be kept in enclosed conveyors or bins for the rest of the process. The wood will be conveyed from the dryer to the hammermill building via a series of conveyors and hoppers that feed four hammermills. The system is designed to operate at full capacity with three hammermills and one stand-by. The hammermills will reduce the size of the wood chips to 0.2 inch. To optimize the capacity of the hammermills the wood will be vacuum conveyed from the hammermill discharges to a surge bin. This surge bin will be used to feed one of two 100 percent capacity conveyor trains up to the boiler feed hoppers. The boiler feed hoppers will be live bottom bins, which can feed at the desired rate into the boiler through the existing coal pulverizer pathway. The pulverizers would be gutted and would not be used as a means of size reduction; they would only provide a path for delivering the woody biomass into the forced air feed system.

Certain parts of the system are fully redundant, some have a targeted percentage redundancy, and some represent a single point of failure: Conveyors were doubled up from the hammermills on to the boiler to ensure continuous feed; the hammermills require frequent maintenance, thus have additional capacity in the fourth mill; and the dryer is a single point of failure item because of its high cost. However, it should be noted that the dryer is expected to have high reliability, since it has been designed for 8,400 hours per year operation. It is recommended that the level of redundancy desired be evaluated in further stages of project development.

2.2.4 Boiler and Air Quality Control Modifications

The combustion system of the boiler will be upgraded from pulverized coal (PC) to co-firing milled and dried biomass with natural gas. It is expected that the natural gas firing system will utilize the existing ignitors and warm-up guns. The milled biomass firing system will utilize new burners and supply piping around the boiler. Milled biomass will be fired at the same elevations as the existing coal nozzles. The cost for new nozzle tips has been included. This concept for biomass supply and firing will need to be confirmed (or adjusted) by a vendor during detailed design.

Milled biomass (from the fuel supply system discussed in Subsection 2.2.3) will be introduced into the existing coal mills where it will be mixed with primary air (PA) and carried through the existing coal piping system to the burners. Since the fuel will be dried and milled prior to introduction into the coal mills, the coal mills will be modified to remove the internals utilized for grinding and will serve only as a mixing and distribution pathway. The temperature for the PA system will need to be reviewed during detailed design, as heated PA for drying is not necessary. A cost allowance for air heater modifications on the primary air side has been included in the estimate.

The air quality control system (AQCS) installation activity should be completed in tandem with the PC boiler modification tasks. Unit 1 is currently equipped with a fabric filter for particulate removal, a wet flue gas desulfurization (FGD) system for sulfur dioxide removal, and a powdered activated carbon (PAC) injection system for mercury removal. The fabric filters should continue to function adequately following the fuel conversion. The following considerations and changes apply to the primary equipment in the AQCS that would need to be reviewed in detail, installed, and/or modified:

- Biomass combustion can sometimes result in unburned fuel embers existing the boiler and traveling with the flue gas through the emissions control equipment. To prevent partially combusted particles from entering the fabric filter, a mechanical dust collector (cyclone) may be required. This additional equipment has been included in the cost estimate for conservatism. As this project moves forward, alternatives such as flame-resistant bags for the fabric filter can be considered as potential ways to eliminate this cost.
- Given the lower sulfur content in biomass and gas than in coal, the wet FGD may no longer be required following the conversion. Therefore, the cost and performance estimates herein have assumed the wet FGD will be decommissioned and abandoned in place. The

plant is expected to save on auxiliary power, spray water, and reagent consumption that is currently utilized to operate the wet FGD following the conversion.

- However, if the unit has a stack designed for wet flue gas, complete removal of the FGD operation may cause the flue gas temperature to increase beyond the stack design temperature. Cholla Unit 1 currently has a stack equipped with a stainless steel liner (Incoloy 27-7). This material should continue to function adequately in the higher temperature environment associated with the decommissioned wet FGD following the fuel conversion. No major modifications are anticipated, although minor components such as expansion joints should be reviewed during detailed design.

- It is also expected that operation of the PAC system will no longer be required following the fuel conversion; the new fuel has no mercury content. The PAC system will be decommissioned and abandoned in place.
- Nitrogen oxide (NO_x) emissions may change following the biomass conversion; the change will depend on the specific vendor burner design, stoichiometry, furnace temperature profile, and several other factors. NO_x mitigation will need to be reviewed during detailed design when more information is available concerning the NO_x emissions and permit requirements. To be conservative, a selective noncatalytic reduction (SNCR) system has been included in the cost estimate to account for the new combustion system modifications. It is possible that the natural gas co-firing system may help to stage combustion in such a way as to reduce NO_x associated with the biomass combustion system, but this will need to be evaluated during detailed design.
- To reduce NO_x emissions, a flue gas recirculation system is sometimes considered for firing of gaseous fuel. This system is not recommended for biomass and gas co-firing in suspension and has not been included in the cost estimate.
- Additional civil/structural support systems, as needed.

Finally, it should be noted that electrical interconnection and instrumentation for all demolished equipment would need to be removed and new lines run for newly-installed equipment.

2.2.5 Utility Requirements

Natural Gas Supply

The new natural gas flow rate to the Unit 1 boiler after repowering of the unit will be based on an energy input rate of 125 MMBtu/hr and is expected to be delivered to the 32 existing natural gas burners located in the windbox assemblies at the four corners of the boiler (including coal burner ignitors, warming guns, and warming gun ignitors). The sizing for the existing high and medium pressure natural gas piping systems is assumed to be adequate but will need to be confirmed during detailed design. The existing low-pressure natural gas piping is undersized (low pressure natural gas piping includes piping downstream of the last pressure regulator, including the supply header to the boiler, ring header around the boiler, "downcomer" headers at each corner of the boiler, and feed lines to each ignitor/gun). The existing low-pressure natural gas piping will be demolished, and new piping and fittings will need to be installed including in-line fittings, valves, strainers, and flexible hoses.

The proposed boiler modifications are considered a "major alteration." Therefore, the natural gas supply shall comply with the current National Fire Protection Agency (NFPA) 85 code. A new boiler management system (BMS) and automated block-and-vent assemblies are anticipated to be required. High level costs for these items have been factored into the capital cost estimate. Automated block-and-vent assembly vent lines will be routed to a safe discharge location, which is considered to be at the top of the Unit 1 powerhouse.

Fire Protection

New fire protection measures will be required for the wood processing equipment in the yard up to the existing coal silos east of the Unit 1 boiler. It is assumed no fire protection changes are required within the Unit 1 powerhouse and that the biomass surge bins, hoppers, etc., will be supplied with their own deflagration venting provisions. Explosion suppression is not included in the present study.

The wood processing equipment in the yard requires the addition of two 3,500 gallons per minute fire water pumps and two redundant 420,000 gallon fire water tanks for fire protection. Alternative locations for the new tanks and pumps were evaluated, and ultimately, the area to the northeast of the coal yard was determined to be the preferred option. An underground fire water loop comprising ductile iron pipe, hydrants, and above ground valve houses is anticipated in the coal yard. The new underground fire water loop could potentially tie into the existing underground 12 inch fire mains header located north of the issuing warehouse building. Deluge systems will be supplied for the biomass conveyors, as well as dust collector pre-action spray systems.

A carbon dioxide (CO_2) fire suppression system will supply CO_2 to the various bins, silos, and hoppers where the wood fuel is expected to accumulate and have significant residence time. The system will comprise a new 3.5 ton CO_2 tank, refrigeration unit, vaporizer skid, and supply piping. The CO_2 tank will be located outdoors and will be refilled via delivery trucks.

2.2.6 Discipline-Specific Design Criteria

The Design Basis Memorandum provides several sections focused on engineering discipline-specific design criteria. The Civil/Structural criteria include environmental, design loads, architecture, concrete, steel structures, site, foundations, and bulk material handling. The Mechanical criteria include boiler modifications, air quality modifications, piping, components, accessories, valves, coatings, freeze protection/temperature maintenance, space conditioning, and fire protection. The Electrical criteria include available power, electric motors, emergency systems, hazardous area classification, grounding, lightning protection, lighting, wiring, raceways, plant communications, and freeze protection/temperature maintenance. Finally, the Instrumentation criteria include control design, control hardware, instruments, and tubing and piping.

2.3 PROCESS FLOW DIAGRAM

The PFD for the new bulk material handling equipment associated with the project (as described in Subsection 2.2.3) is included in Appendix C.

2.4 EQUIPMENT LIST

The equipment list is included in Appendix D and it enlists all new bulk material handling equipment, BOP equipment, and new AQCS equipment.

2.5 SITE PLAN

The site plan consists of a general arrangement (GA) drawing (included in Appendix E) for the Cholla Power Plant site showing the major modifications anticipated as a result of the Unit 1 repowering project.

2.6 ELECTRICAL LOADS AND ONE-LINE DIAGRAM SUMMARY

A summary of the electrical load list by major electrical equipment is provided in Table 2-3. Total power (in kilovolt-amperes [kVA]) is reported for each major system. Taking into account duty cycles, the total parasitic load for new wood yard equipment is estimated to be 2,557 kilowatts (kW); the other required electrical loads are estimated to be 4,093 kW. This indicates that the net parasitic load is 6,650 kW, which yields a net power generation of 83.2 MW exported to the grid when subtracting from the gross expected generator output of approximately 89.9 MW.

Table 2-3 Summary of Electrical Load List

MAJOR EQUIPMENT NAME	ELECTRICAL LOADS *kVA*	ELECTRICAL LOADS *kW*
Receiving Hopper	172	146
Belt Conveyors	95	81
Slewing Belt Stacker	44	37
Slewing Boom Reclaimer	302	257
Air Density Separator	171	146
Disc Screen	15	13
Crusher	144	122
PowerScrew Systems	409	348
Dryer	397	337
Flight Chain Conveyors	83	70
Hammermills	627	533
Fire Water Pumps and Valve Houses	9	8
Transformers	540	459
SUBTOTAL Wood Yard Electrical Loads	3,008	2,557
SUBTOTAL Other Required Electrical Loads	4,815	4,093
TOTAL NET PARASITIC ELECTRICAL LOAD	7,823	6,650

The electrical one-line diagram corresponding to these loads is included in Appendix F.

2.7 CONTROL SYSTEM APPROACH

The Design Basis Memorandum includes a philosophy of how control of the new wood yard equipment and the modified plant equipment would be achieved. These design basis assumptions were used to develop budgetary costs for equipment control. A summary of the approaches taken to establish budgetary pricing for control of the new and modified equipment is included in the following subsections.

2.7.1 Wood Yard Control System

Budgetary pricing on the wood handling equipment was solicited from various suppliers. As part of this budgetary request for pricing, the equipment vendors were requested to provide pricing for a Programmable Logic Controller (PLC)-based control system for the equipment to be supplied as part of the wood handling equipment scope of supply. Therefore, control system costs for the wood yard equipment are included in the overall budgetary pricing received from the wood yard equipment vendors.

2.7.2 Control System Modifications to Existing Equipment

Appendix C shows the proposed PFD for the plant modifications. On the PFDs, new equipment is shown in bold, and existing equipment to remain is shown with dashed lines. The interface between the new wood yard equipment and the existing boiler equipment will be the boiler feed bins, which will remain in operation. The existing boiler control system will be modified to receive interlocks to and demand signals from the new wood yard PLCs, which replaces the prior coal yard control system. Since the bulk of control of the new wood handling equipment will be in vendor supplied PLCs, only a small amount of interlocks and demand signals will have to be added to the existing boiler control system. Supervisory commands from the boiler control system master fuel controller to the new wood handling equipment PLCs will be utilized to keep the boiler feed bins appropriately filled for normal operation of the boiler. Budgetary pricing for modification to the existing boiler control system to accommodate supervisory control of the new wood handling equipment has been provided as part of the EPC cost estimate.

3.0 Project Schedule and Cost Estimates

3.1 EPC SCHEDULE

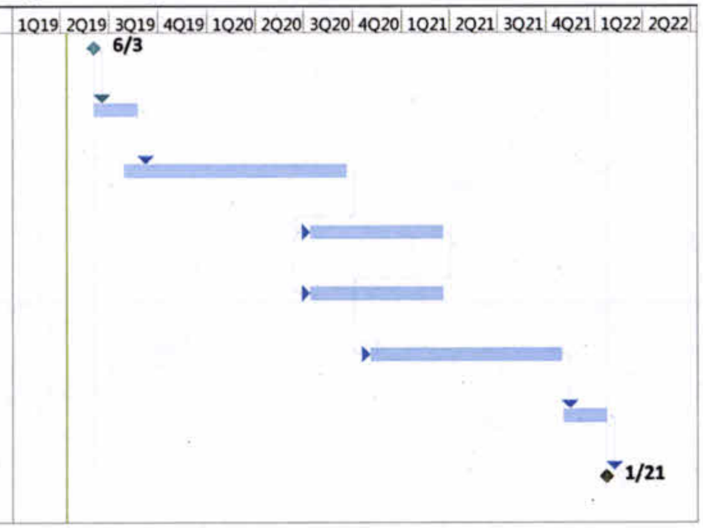
A preliminary Level 1 EPC schedule for the Cholla Unit 1 Biomass Repowering Project is shown in Figure 3-1. Key milestone dates for major events as part of the execution of this project are listed in Table 3-1 in months after notice to proceed (NTP) through commercial operation date (COD). It is expected that Cholla Unit 1 would be out of service for 10 to 12 months during construction, depending on site work requirements for the new equipment. Furthermore, according to the design presented in this report, it is expected that Cholla Units 3 and 4 could remain in operation during the biomass repowering construction and operation of Unit 1.

Table 3-1 Key Milestone Dates

PROJECT MILESTONE	DATE AFTER NTP
Preliminary Engineering	3 months
Permitting (Major Modification)	16 months
Detailed Engineering	22 months
Procurement	22 months
Construction	29.5 months
Commissioning and Testing Completion	32 months
Commercial Operation Date	32 months

APS Cholla Unit #1 Biomass Repowering Schedule

ID	Task Name	Duration	Start	Finish
1	NTP	0 days	Mon 6/3/19	Mon 6/3/19
2	Preliminary Engineering	60 days	Mon 6/3/19	Fri 8/23/19
3	Permitting (Major Modification)	300 days	Mon 7/29/19	Fri 9/18/20
4	Detailed Engineering	180 days	Mon 7/13/20	Fri 3/19/21
5	Procurement	180 days	Mon 7/13/20	Fri 3/19/21
6	Construction	260 days	Mon 11/2/20	Fri 10/29/21
7	Start-Up and Commissioning	60 days	Mon 11/1/21	Fri 1/21/22
8	COD	0 days	Fri 1/21/22	Fri 1/21/22



Project: APS Cholla Unit1 Biomass
Date: Sat 4/13/19

Task	Manual Summary Rollup
Split	Manual Summary
Milestone	Start-only
Summary	Finish-only
Project Summary	External Tasks
Inactive Task	External Milestone
Inactive Milestone	Deadline
Inactive Summary	Progress
Manual Task	Manual Progress
Duration-only	

Figure 3-1 **Preliminary Level 1 EPC Project Schedule**

3.2 PROJECT COST ESTIMATES

3.2.1 Cost Estimate Basis

Black & Veatch prepared a conceptual cost estimate that is classified as an American Association of Cost Engineers Class Four estimate with an accuracy of +40 percent to -15 percent. Furnish and erect packages and equipment material prices were estimated primarily using vendor budgetary quotations for the material handling and drying systems. The balance of equipment was estimated using in-house pricing based on historical project data. All costs are expressed in first quarter 2019 US dollars (USD).

Equipment/Key Supplier List

Budgetary quotations were received for the woody biomass handling systems and the biomass dryer.

Boiler, AQCS, and Ash Handling Modifications and Equipment

In-house historical project data pricing was used to estimate the costs associated with the new equipment including biomass burners, mechanical dust collector, and SNCR. Cost provisions for modifications to the existing coal mills and PA system, as well as decommissioning of the FGD and PAC systems are included. Ancillary costs associated with civil/structural support systems and electrical interconnection were estimated on the basis of historical project experience. Finally, Black & Veatch has included a provision for conversion of the existing wet bottom ash handling/pond system to a submerged flight conveyer bottom wood ash disposal method, once again on the basis of prior experience.

Civil and Structural

Concrete, rebar, and formwork quantities estimates were based on information received in equipment quotations and from Black & Veatch internal estimates for BOP. Metal deck and structural steel quantities were also estimated for the boiler hopper elevated slab. Asphalt pavement quantities were based on new roads depicted in the GA drawing and assume a 16 inch roadway thickness. Pilings were designed on a preliminary basis using limited geotechnical information for the site and equipment loading data received from vendors.

Mechanical and Piping

Mechanical piping and equipment bill of quantities for natural gas supply to the boiler, fire water supply to the wood fuel yard, and CO_2 supply to the wood silo were determined on the basis of the GA drawing, applicable NFPA codes, and tie-in information provided by APS. Structures have been included for housing certain valves and pumps, as appropriate.

Electrical and Instrumentation

Electrical tie-in is based on interconnection with medium-voltage Switchgears 28 and 29, in accordance with the Cholla Unit 1 GA drawing. Cables, raceways, and other ancillary electrical supply equipment estimates were based on analogous in-house techniques. Electrical systems for the fuel yard equipment (power distribution centers, motor control centers, transformers, etc.) were also estimated on an analogous basis using recent in-house cost data. New instrumentation will include a continuous emissions monitoring system and PLC for the fuel dryer and wood yard equipment, in addition to new supervisory control of the wood yard equipment from the existing boiler control system.

Engineering and Construction

All labor costs have been adjusted to reflect Arizona rates and productivity. The costs reflect an EPC execution approach. Engineering has been included at 10 percent of total direct costs plus subcontractor indirects. Similarly, construction management costs are estimated at 6 percent of total direct costs plus subcontractor indirects based on the EPC schedule.

Indirects and Exclusions

The capital cost estimate represents an overnight cost with no provisions for escalation. A contractor's contingency of 20 percent of the total installed cost (TIC) is carried. General liability and builder's all-risk insurance is estimated as a percentage of TIC. An EPC contractor's fee of 7 percent is also included. Exclusions from this cost estimate include permitting, capital spares, taxes/duties, liability insurance, letters of credit/bonds, tariff impacts, hazardous materials handling/abatement, and other Owner's costs.

3.2.2 EPC Capital Cost Estimate

A summary of the capital cost estimate is shown in Table 3-2; the full cost estimate basis and detailed capital cost estimate are attached in Appendix G. The total capital cost for the project is estimated at $134,567,000.

3.2.3 Operations and Maintenance Cost Estimate

The estimated annual non-fuel O&M costs are summarized in Table 3-3. All variable expenses, with the exception of consumables and mobile equipment, were scaled and adjusted on the basis of actual O&M data on coal plant operations provided by APS and differences in USD/megawatt-hour for coal versus biomass operations. Consumables estimates were based on expected adjusted chemical consumption using biomass fuel and excluding AQCS equipment that will no longer be in use. Mobile equipment expense estimates were based on Black & Veatch experience and includes fuel.

All fixed expenses were estimated using actual O&M data provided by APS. Labor expenses were calculated assuming 28 personnel working in the Unit 1 powerhouse and four personnel working in the fuel yard at an average plant staff salary of $102,000 per year. Contingencies for both variable and fixed O&M expenses were estimated assuming 5 percent of all other costs in each category. The total annual non-fuel O&M cost is estimated at $10,694,000 per year.

Table 3-2 Summary of EPC Capital Cost Estimate

DESCRIPTION	TOTAL COST
Direct Costs	
Site Work	$1,227,000
Foundations and Concrete	$10,582,000
Material Handling Equipment	$33,492,000
Steel	$752,000
Boiler and AQCS Modifications	
Boiler and Combustion System Modifications	$8,000,000
Mechanical Dust Collector (allowance)	$2,200,000
SNCR (allowance)	$6,000,000
Fire Protection	$4,006,000
Ash System Modification	$6,714,000
Piping	$639,000
Electrical	$3,175,000
Instrumentation and Control Systems	$518,000
Insulation and Fireproofing	$60,000
Total Direct Cost	$77,365,000
Indirect Costs	
Construction Management and Startup Staff	$5,195,000
Scaffolding	$3,073,000
Major Construction Equipment	$2,169,000
Subcontractor Indirects	$9,217,000
Engineering	$8,658,000
Contingency	$20,087,000
EPC Fee	$8,803,000
Total Indirect Field Costs	$53,916,000
TOTAL CAPITAL COST	**$134,567,000**

Table 3-3 Summary of Annual Non-Fuel O&M Costs

DESCRIPTION	TOTAL COST
Variable Expenses	
Annualized Maintenance for Equipment	
BoP Systems	$238,000
Boiler Systems	$271,000
Electrical Systems	$144,000
Fuel Systems	$463,000
SNCR System	$180,000
Turbine/Generator Systems	$84,000
Consumables/Chemicals	$1,127,000
Dam Systems	$10,000
Environmental Systems and Compliance	$23,000
Facility Maintenance	$718,000
Mobile Equipment Maintenance or Lease	$50,000
Other	$886,000
Variable O&M Contingency	$210,000
Subtotal Variable Expenses	**$4,404,000**
Fixed Expenses	
Direct Labor	$4,102,000
Accounting, Payroll, Human Resources, Audit	$1,140,000
Other Labor Expenses	$562,000
Regulatory Fees	$16,000
Insurance	$126,000
Legal	$44,000
Fixed O&M Contingency	$300,000
Subtotal Fixed O&M	**$6,290,000**
TOTAL O&M	**$10,694,000**

4.0 Conclusions

The Cholla Power Plant Unit 1 was originally commissioned in 1962 and has a capacity of 113.6 MW when operated on coal fuel. APS was ordered in August 2017 to evaluate the use of forestry biomass to produce electric power, for which Black & Veatch has provided support by investigating a number of alternatives across numerous studies. Black & Veatch was then engaged by APS to provide a conceptual design and cost estimate for the repowering of Cholla Unit 1 with biomass and natural gas to determine the cost of producing power from forestry biomass.

Through prior study work, Black & Veatch recommended that co-firing natural gas with dried/sized biomass in Cholla Unit 1 offered the greatest promise to achieve stable operations while maximizing biomass power generation at 75 percent rated load (90 MW gross). A design basis memorandum was prepared to document the manner in which this could be achieved via the installation of new bulk material handling equipment and the modification of the existing boiler and AQCS equipment. Incoming wood would be milled to a maximum of 0.2 inch size and dried to 15 percent moisture before being conveyed to the existing coal mills, which would be modified to remove internal components and facilitate fuel mixing and distribution. For the AQCS modifications, it is envisioned that existing FGD and PAC equipment can be abandoned in place, while a new mechanical dust collector system would be installed to supplement the existing baghouse for particulate removal, and a new SNCR system would be installed for NO_x removal. For ash handling, the existing wet ash system would be converted to a submerged flight conveyor approach.

A PFD, equipment list, and GA drawing were developed using the design basis to indicate how these new and modified systems would be integrated and laid out on the Unit 1 site. BOP systems primarily focused on utilities, including electrical distribution, natural gas, and fire water service, were further considered as part of design activities. An electrical one-line diagram was prepared to document how new loads would integrate with existing plant electrical distribution centers. Black & Veatch estimates that the total parasitic load for new equipment would be 2,557 kW. This indicates that the net parasitic load would be 6.65 MW, which yields a net power generation of 83.2 MW exported to the grid. The plant is expected to produce this net power while consuming 151,000 lb/hr of 30 percent moisture biomass (into the dryer) and 125 MMBtu/hr of natural gas, resulting in a net plant heat rate of 12,700 Btu/kWh.

It is estimated that execution of the Cholla Unit 1 Biomass Repowering Project would be 32 months in duration from the NTP of preliminary engineering, through permitting, detailed design, procurement, construction, and startup/commissioning. An EPC-based capital cost estimate was prepared, with the results showing the cost at approximately $134,567,000 with +40 percent/-15 percent accuracy. The annual non-fuel O&M cost was estimated to be approximately $10,694,000. APS will be preparing its own levelized cost estimate of power production with the repowering facility using these key inputs (including the costs for wood and natural gas fuel) to discern the economic viability of the project.

The following conclusions are made with respect to this study:

- A more detailed design should be developed to confirm the various assumptions that were used as the basis for this study and formulate the basis for permit applications.
- APS may consider an alternative execution strategy to the proposed EPC-based approach to further explore financial costs and risks associated with the repowering option for Cholla Unit 1.

Appendix A. Acronyms

ACC	Arizona Corporation Commission
AF	As-Fed
APS	Arizona Public Service Co.
AR	As-Received
AQCS	Air Quality Control System
BMS	Burner Management System
BOP	Balance-of-Plant
CO_2	Carbon Dioxide
COD	Commercial Operation Date
db	Dry Basis
EPC	Engineering, Procurement, and Construction
FGD	Flue Gas Desulfurization
GA	General Arrangement
hr	Hour
kVA	Kilovolt Ampere
kW	Kilowatt
kWh	Kilowatt-Hour
lb	Pound
MMBtu	Million British Thermal Units
MW	Megawatts
NFPA	National Fire Protection Agency
Nitrogen Oxide	NO_x
NTP	Notice to Proceed
O&M	Operations and Maintenance
PA	Primary Air
PAC	Powdered Activated Carbon
PC	Pulverized Coal
PFD	Process Flow Diagram
PLC	Programmable Logic Controller
SNCR	Selective Noncatalytic Reduction
TIC	Total Installed Cost
US	United States
USD	US Dollars

Appendix B. Design Basis Memorandum

FINAL

CHOLLA BIOMASS REPOWERING DESIGN BASIS

B&V PROJECT NO. 401613
B&V FILE NO. 40.0100

PREPARED FOR

aps

Arizona Public Service Company

26 APRIL 2019

BLACK & VEATCH

Table of Contents

LIST OF TABLES

1.0 General Information

Client's Name: Arizona Public Service Company (APS)
Facility Location: Joseph City, Arizona, USA
Unit Type: Power Station

1.1 OBJECTIVE

The purpose of this document is to:

- Define the basis used for designing Cholla Unit 1 to be fueled by biomass rather than coal.
- Record input information received from the Client that will be used in the preparation of the design.

1.2 SCOPE

Black & Veatch is evaluating the modification of an existing coal-fueled power plant in Joseph City, Arizona to be fueled by woody biomass. This modification includes the installation of new woody biomass receiving, storage, processing, and boiler delivery equipment. Black & Veatch's scope is to investigate the potential to utilize existing on-site equipment and utilities (e.g. fuel receiving, boiler ancillaries, air quality control, ash handling, etc.) and specify any balance of plant equipment needed.

1.3 UNITS

Variables and engineering units to be used for this project are shown in Table 1-1.

Table 1-1 Variables and Engineering Units

Variable	Engineering Units
Temperature	°F
Pressure	
Near Atmosphere	psig
Above Atmosphere	psig
Below Atmosphere	in H_2O
Absolute	psia
Level	
Process	ft, inches
Storage tanks	ft, inches
Flow	
Gas Volume	SCFH
Gas Mass	lb/hr
Liquid Volume, Process flows	GPM
Liquid Volume, Utility flows	GPM
Liquid Mass	lb/hr
Solid Mass	lb/hr, tons/hr (tph)
Distance	ft, inches
Velocity	ft/s, ft/min
Length	ft
Thermal Conductivity	Btu/(hr ft °F)

Variable	Engineering Units
Gross Heating Value	Btu/lb
Net Heating Value	Btu/lb
Density	lb/ft^3
Weight	lb, tons
Soil Bearing Pressure	psf
Heat/Thermal Duty	MMBtu/hr
Sound Pressure Level	dBA

1.4 DESIGN CODES AND STANDARDS

The design and specification of work will be in accordance with applicable state and federal laws and regulations, and local codes and ordinances. The codes and industry standards used for design, fabrication, and construction are listed below and will be the editions in effect, including all addenda, as of the Design Freeze date. Other recognized standards may also be used as design, fabrication, and construction guidelines when not in conflict with the listed standards. Applicable codes shall be finalized during detailed design:

- American Concrete Institute (ACI).
- American Institute of Steel Construction (AISC).
- American Iron and Steel Institute (AISI).
- American National Standards Institute (ANSI).
- American Petroleum Institute (API).
- American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE).
- American Society of Mechanical Engineers (ASME).
- American Society for Testing and Materials (ASTM).
- American Water Works Association (AWWA).
- American Welding Society (AWS).
- Applicable Arizona Building Code.
- Applicable Arizona Plumbing Code.
- Conveyor Equipment Manufacturers Association (CEMA).
- Cooling Tower Institute (CTI).
- Compressed Gas Association (CGA).
- Concrete Reinforcing Steel Institute (CRSI).
- Environmental Protection Agency 40 CFR Part 60 and 40 CFR Part 75 (EPA).
- Illuminating Engineering Society (IES).
- Institute of Electrical and Electronics Engineers (IEEE).
- International Organization for Standardization (ISO).
- International Society of Automation (ISA).
- Insulated Cable Engineers Association (ICEA).
- National Electric Code (NEC).
- National Fire Protection Association (NFPA).
- National Institute of Standards and Technology (NIST).
- Occupational Safety and Health Administration (OSHA).

2.0 Site Information

2.1 SITE CONDITIONS

Site-specific design criteria are shown in Table 2-1.

Table 2-1 Site-Specific Design Criteria

Design Barometric Pressure:	12.28 psia [NOTE 1]
Elevation:	5,030 ft
Design Minimum Ambient Temperature:	-5.6 °F [NOTE 1]
Design Maximum Ambient Temperature (dry bulb):	105.7 °F [NOTE 1]
Design Maximum Ambient Temperature (wet bulb):	80.1 °F [NOTE 1]
Fuel:	Woody biomass co-fired with natural gas
Plant Cooling:	From Existing Cooling Water Booster System

NOTES

1. Based on ASHRAE HVAC design data for Winslow (AUT), Arizona weather station.

2.2 DESIGN BASIS WATER

The water used throughout the facility (e.g. cooling water makeup, fire water, service/potable water) should suffice after the fuel change is implemented, because the fuel change will have no impact on water quality requirements. The heat rejection system is assumed to be not affected by the Unit 1 conversion to biomass.

2.3 ENVIRONMENTAL EMISSIONS AND EFFLUENTS

A permit has not been obtained for the site for use of biomass as a fuel. With the changes made to the boiler, such as new burners, a new permit would be required, and with a new fuel source, the emission limits for the facility could be significantly different. Emissions are evaluated on a qualitative manner, because official permitted numbers have not been provided.

2.4 NOISE LIMITATIONS

The near-field noise emissions for each equipment component furnished shall not exceed a spatially-averaged, free-field, A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 ft above floor/ground level and any personnel platform during normal operation. The equipment envelope is defined as the perimeter line that completely encompasses the equipment package at a distance of 3 ft horizontally from the equipment face.

Where the drive motors, variable frequency drives (VFDs), or mechanical drives for the equipment are also furnished, the total combined near-field sound pressure level of the motor, VFD, or mechanical drive and the driven equipment measured as a single component, operating at design load, shall not exceed a spatially-averaged, free-field, A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope.

During off-normal and intermittent operation such as start-up, shut-down, and upset conditions the equipment sound pressure level shall not exceed a maximum of 110 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

2.5 SITE ACCESS

The site is located directly off Interstate 40 down a short length of frontage road. Unit 1 is located on the east side of the line of four boilers and is separated from Unit 2 by approximately 30-50 feet at most locations as a stand-alone unit. The fuel handling system utilizes a main reclaim conveyor and system which is separate from the other units. The plant is subjected to high winds at times, which will require that the biomass material be protected. The current main coal conveyors are enclosed in circular corrugated tubing. The Unit 1 boiler housing is open to the environment, which has been known to cause heat transfer problems and rapid cooling during low temperatures, especially when the boiler trips.

The boiler combustion belt region is easily accessible by four platform levels.

- Under burner level: The under-burner level is mostly clear, save for the corners where the four coal pipes travel upwards. The backpass side of the furnace (north side) is tighter and more constrained.
- Lower D/C burner level: Burners are labeled "D" for the bottom burner, and up through "A" as the top burner. The "C" burner level is very close to the flooring above and may represent some installation challenges.
- Upper A/B burner level: This burner level has easier access than the D/C level.
- Separated overfire air level: The OFA ductwork restricts access to the east and west sides of the boiler, and the north side (facing the backpass) is also tight clearance.

Access to the backpass between the economizer and the air heater is restricted significantly on the boiler-facing side, but very open on the north (air quality control system facing) side. Access for ductwork < 3-ft in size is possible on the east and west sides.

3.0 Utility Requirements

Utilities required for the facility are shown in Table 3-1.

Table 3-1 Utility Requirements

Utility	Utility Supply Information
Steam	Not required
Nitrogen	Not required
Carbon Dioxide	CO_2 for fire suppression in wood fuel bins/hoppers supplied by outdoor CO_2 tank. Flow rate TBD during detailed design
Instrument Air	TBD during detailed design
Cooling Water	Not required
Service/Potable Water	TBD during detailed design
Fire Water	3,500 gpm fire water supply required for wood handling/processing equipment
Natural Gas	125 MMBtu/Hr NG supply required at Unit 1 boiler

4.0 Process Data Tables

4.1 FEEDSTOCK

Table 4-1 shows the woody biomass feedstock to be delivered to Cholla and processed on-site for delivery to and utilization by the existing boiler.

Table 4-1 Feedstock Design Basis

Parameter	Unit	Ponderosa Pine
As received basis (AR)	Wt%	100
As fed basis (AF)	Wt%	100
Dry Basis (db)	Wt%	100
Proximate Analysis		
Moisture AR	Wt%	30.00
Moisture AF	Wt%	15.00
Volatile Matter	db%	83.96
Ash	db%	0.57
Fixed Carbon	db%	15.47
Ultimate Analysis		
Carbon	db%	51.25
Hydrogen	db%	6.21
Nitrogen	db%	0.14
Oxygen	db%	41.78
Sulfur	db%	0.05
Ash	db%	0.57
Moisture	db%	15.00
Heating Value		
HHV, db	Btu/lb	8,806
Other Parameters		
Chlorine	db%	0.01
Mass Flow (wood into dryer)		151,000 lb/hr
Feedstock Size AR		3½" x 3½" x 3/4"
Feedstock Angle of repose		45°

5.0 Civil/Structural Design Basis

5.1 ENVIRONMENTAL CRITERIA

Load calculations are based on ASCE 7-10.

5.1.1 Rainfall

- 100-Year, 1-Hour Rainfall: 1 inch.
- 100-Year, 12-Hour Rainfall: 3 ½ inches
- 100-Year, 24-Hour Rainfall: 4 inches
- Maximum recorded in 24 hours (25-year frequency): 3 ½ inches

5.1.2 Wind

- Basic Wind Speed, mph: 120
- Exposure Category: D
- Topographic Factor, Kzt: 1.0

5.1.3 Seismic

- Short Period Mapped Spectral Acceleration, Ss: 0.191
- One Second Period Mapped Spectral Acceleration, S1: 0.062
- Site Class: D
- Importance Factor (Seismic Loads), Ie: 1.5

5.1.4 Snow

- Ground Snow Load, Pg, lb/ft^2: 10
- Importance Factor (Snow Loads), Is: 1.20

5.2 DESIGN CRITERIA

5.2.1 Design Loads

Design loads and load combinations for all buildings, structures, structural elements and components, handrails, guardrails, and connections shall be determined according to the criteria specified in this section (refer to Table 5-1). Loads imposed on structural systems from the weight of all temporary and permanent construction, occupants and their possessions, environmental effects, differential settlement, and restrained dimensional changes shall be considered.

The live loads used in the design of buildings and structures shall be the maximum loads likely to be imposed by the intended use or occupancy, but will not be less than the minimum uniform live loads presented in Table 5-2, Table 5-3, and Table 5-4. Components of the structural system may be designed for a reduced live load in accordance with the local building code. Roofs shall be designed to preclude instability resulting from ponding effects by ensuring adequate primary and secondary drainage systems, slope, and member stiffness. Structural elements supporting equipment shall be designed for the greater of the uniform live load or the loading imposed by the actual equipment.

Buildings and Other Structures

Process buildings shall have vertical bracing positioned to maintain a regular structure classification. Rigid structures, such as turbine equipment support structures, shall be isolated from the turbine building structure so that each provides its own discrete lateral force resisting system, unless coordinated and calculated to meet the regular structure classification.

All buildings shall have bracing located so as to minimize internal restraint to dimensional changes. Component supports and anchorages shall be configured so as to be rigid.

Table 5-1 Design Loads

Load Types	Criteria/Source
Dead Loads	ASCE 7-10, Tables C3-1 and C3-2.
Pipe Support, major piping (Major piping is defined as hot pipe greater than or equal to 2-1/2 inches [65 mm] in diameter and cold pipe greater than or equal to 24 inches [610 mm] in diameter.)	Specifically determined, including thermal and dynamic loads, and verified against final pipe routing and analysis.
Pipe Support, other piping and electrical conduit and cable tray	Preliminary design for uniform area, line, and/or concentrated loads located to create contingency moments and shears.
Live Loads	Calculated weight of the contents of tanks; movable loads, such as people, equipment, tools, and components during construction, operations, and maintenance; maximum loads likely to be imposed by intended use or occupancy, but not less than the loads in Table 5-2, nor actual equipment weight.
Impact Loads	Table 5-2 loads allow for ordinary impact conditions. Reciprocating or rotating machinery, elevators, cranes, pumps, and compressors shall have specific calculations addressing dynamic forces. Impact loads shall be as specified in ASCE 7 Chapter 4 unless analysis indicates higher values are required.
Soil and Hydrostatic Loads	Below grade structures shall include static and seismic lateral soil pressure, expansive soil pressures, hydrostatic pressure or buoyancy, compaction energy pressure, and potential surcharge loads from normal service or construction.
Wind Loads, buildings and structures	Basic design wind speed shall be in accordance with ASCE 7, Subsection 1.7.2. No shielding shall be permitted for ground conditions or for adjacent structural members.
Wind Loads, steel stacks	Loads and design in accordance with ASME STS-1.
Snow Load	Minimum ground snow load shall be in accordance with ASCE 7, Subsection 1.7.2. Drift loads shall be applied to roof discontinuities and roof regions shielded by large roof-mounted equipment or machine penthouses.
Ice Loads	Applicable to steel lattice type structures and guy cables. Ice accretion shall be in accordance with ASCE 7, Subsection 1.7.2. An ice density of 57 lb/ft^3 (915 kg/m^3) shall be used.
Seismic Loads, buildings (by building, if appropriate)	Refer to ASCE 7, Subsection 1.7.2.
Seismic Loads, components and attachments	Amplification and response modification factors in accordance with ASCE 7.

Load Types	Criteria/Source
Construction Loads, roads	AASHTO HS 20 or equivalent.
Fatigue Loads	In accordance with AISC Specification for Structural Steel Buildings.
Personnel Load	
Fixed Metal Ladders	One 300 pound load for every 10 feet of ladder height or two 300 pound concentrated loads between any two consecutive attachments, whichever is greater. Rungs are designed for a single concentrated load of 300 pounds.
Stairs	1,000 pound concentrated load applied at any point. Non-concurrent with 100 psf live load in Table 5-2.

Table 5-2 Minimum Uniform Live Loads

Area	Live Load, psf (kN/m²)
Ground Floor Slabs	
Boiler area	150 (7.2)
Turbine area	150 (7.2)
Shops, warehouses	125 (6.0)
Other structures	100 (4.8)
Suspended Floors	
Turbine operating floor	Weight of major components, but not less than 250 (12.0)
Control Room	100 (4.8)
Storage Areas	Weight of stored material, but not less than 125 (6.0)
Other Concrete Floors	100 (4.8)
Grating Floors	60 (2.9)
Roofs	20 (1.0)
Stairs	100 (4.8)
Cooling Tower Decks	60 (2.9)

Table 5-3 Bulk Material Unit Weights: Fuels

	Live Load, psf (kN/m²)	
Item	Volume Design, pcf (kg/m³)	Structural Design, pcf (kg/m³)
Wood Chips		
As Received	11 (176)	18 (290)

	Live Load, psf (kN/m²)	
Item	**Volume Design, pcf (kg/m³)**	**Structural Design, pcf (kg/m³)**
As Fired	9 (144)	15 (240)

Table 5-4 Bulk Material Unit Weights: Ash and Byproducts

	Unit Weight (Bulk Material Density)	
Item	**Volume Design, pcf (kg/m³)**	**Structural Design, pcf (kg/m³)**
Fly Ash		
Precipitator or fabric filter hoppers	35 (560)	42 (670)
Storage silo	35 (560)	42 (670)
Ductwork or pneumatic line	35 (560)	42 (670)
Compacted landfill (dry density)	35 (560)	42 (670)
Bottom Ash		
Hoppers	50 (800)	60 (960)

Construction Loads

Construction or crane access considerations may dictate the use of temporary structural systems. Special considerations will be made to ensure the stability and integrity of the structures during any periods involving use of temporary bracing systems.

Wheel Loads

Wheel loads will be considered for roadway pavements, bridges, buried piping, culverts, and embankments. Roadway subgrades, pavements, and structures shall be designed for HS20 or equivalent load.

5.2.2 Architecture

Exterior Architecture Criteria

The exterior architectural systems provide a durable, weathertight enclosure to protect systems and personnel and allow for a controlled interior environment. Exterior architectural systems shall conform to the general design criteria in Table 5-5 for main plant buildings and principal yard buildings.

Interior Architecture Criteria

The interior architectural systems provide a functional, low maintenance, aesthetically pleasing environment. The materials in Table 5-6 have been selected to provide durability and offer flexibility in responding to occupant demands, while satisfying project and code requirements.

Interior architectural systems shall conform to the general design criteria in Table 5-6 for main plant buildings and principal yard buildings.

Egress Criteria

Equipment platforms are considered unoccupied spaces as defined by IBC and access to them will be as required by NFPA 101 Chapter 40. Following is a list of equipment platforms that will follow the Chapter 40 requirements:

- Process unit stair towers that service open structures and platforms.
- Tanks.
- Cooling towers.
- Utility racks.

Table 5-5 Exterior Architecture Criteria

Item	Criteria
Walls	May consist of insulated or uninsulated metal wall panel. Building enclosures may also be preengineered.
Roofs	May consist of an insulated metal standing seam panel system or single-ply membrane over insulation and a metal roof deck.
Masonry	May consist of concrete block, which may be utilized for enclosure and separation purposes.
Thermal Insulation	Shall have insulation incorporated into the walls and roofs for thermal design and meet energy codes.
Acoustical Insulation	Shall have insulation incorporated into the walls and roofs for acoustical design.
Louvers	Shall include vertical storm louvers as required by the ventilation design.
Windows	May include windows, frames, and glazing. Selection shall be based on project and environmental requirements.
Personnel Doors	Shall include hollow, metal type personnel doors. Insulation and fire rating criteria shall be dictated by the interior and environmental requirements.
Equipment Access Doors	Shall include large exterior doors of the rolling metal type, with weather seals and windlocks.
Finish Painting	Exterior steel materials not galvanized or factory finished shall be field painted. Colors shall be selected and will harmonize with the project color scheme.

Table 5-6 Interior Architecture Criteria

Item	Criteria
Partitions	Partitions constructed of masonry, drywall, or metal wall panel.
Windows	Interior fixed windows as required by the occupancy. Rated and nonrated glazing shall be installed in accordance with fire and building code criteria.

Item	Criteria
Personnel Doors	Hollow, metal type personnel doors. Insulation and fire rating criteria shall be dictated by the interior and environmental requirements.
Ceilings	Ceilings in finished areas of the main buildings and principal yard buildings shall generally consist of suspended, exposed grid, lay-in acoustical type systems. Wet areas shall consist of moisture resistant materials.
Floor Coverings	Floor coverings in finished areas shall generally consist of resilient tiles or carpet tiles. Floor coverings in control and electrical equipment rooms may be static dissipative. High moisture areas shall incorporate unglazed ceramic tiles.
Wall Coverings	Glazed wall tiles shall be used in shower and toilet rooms as required for maintenance and sanitary requirements. All other finished area walls shall be coated as identified in the painting section.
Finish Painting	Interior areas shall be coated where required for chemical resistance, light reflection, or aesthetics.
Sanitary Facilities	Toilet and shower facilities and associated accessories shall be provided where required to meet code and project requirements.

In open structures, such as process units and cooling towers, plant scheduled routine maintenance shall be achieved with three or less occupants. Egress for plant scheduled routine maintenance is accomplished with a common path of travel of 200 feet and/or a ladder used as a second means of egress. Occupancy limits of the structure shall be achieved through signage and Owner administrative controls.

5.2.3 Concrete

Reinforced concrete structures shall be designed in accordance with ACI 318, Building Code Requirements for Structural Concrete, and the design parameters in Table 5-7, Table 5-8, and Table 5-9.

Mix Design

Mix design shall be in accordance with Table 5-7. A larger coarse aggregate size may be considered for mass concrete. Grout is "sand-only" mix.

Table 5-7 Mix Design

Mix Class	Maximum Exposure Classes *	Usage	Design Strength at 28 Days, psi (kPa)	Cement Type	Maximum Water/ Cementitious Materials Ratio	Air Content, percent	Maximum Coarse Aggregate Size, in. (mm)	Max Slump, in. (mm)
A1	NA	Lean work slabs, duct bank, fill concrete	2,000	I, II, or V	0.75	0	1.5 (38)	6 (150)
B1	F0 S0 P1 C1	General usage – no freeze/thaw	4,000	I, II, or V	0.50	3-6	1 (25)	4 (100)
B2	F2 S0 P1 C1	General usage – with freeze/thaw	4,500	I, II, or V	0.45	6	1 (25)	4 (100)
C1	F2 S1 P1 C1	Structure in contact with water or exposed to moderate sulfate exposure	4,500	I (C_3A<5%), II, or III (C_3A<8%),	0.45	6	1 (25)	4 (100)
C2	F2 S2 P1 C1	Structure in contact with water or exposed to severe sulfate exposure	4,500	I (C_3A<5%), III (C_3A<8%), or V	0.42	6	1 (25)	4 (100)
D1	F0 S0 P1 C1	Foundation piers and cased reinforced concrete piling – no freeze/thaw	4,500	I, II, or V	0.50	0	0.75 (20)	4 (100)

Mix Class	Maximum Exposure Classes *	Usage	Design Strength at 28 Days, psi (kPa)	Cement Type	Maximum Water/ Cementitious Materials Ratio	Air Content, percent	Maximum Coarse Aggregate Size, in. (mm)	Max Slump, in. (mm)
D2	F2 S0 P1 C1	Foundation piers and cased reinforced concrete piling – with freeze/thaw	4,500	I, II, or V	0.45	6	0.75 (20)	4 (100)
E1	F0 S0 P1 C1	Underwater concrete	4,000	I, II, or V	0.45	3-6	1 (25)	6-9 (150-225)
F1	F2 S2 P1 C1	Sulfur pits	4,500	V (C_3A<6%)	0.40	6	0.75 (20)	3 (75)

* Refer to Chapter 4 of ACI 318 for exposure classes.

Materials Usage

Table 5-8 Materials Usage Requirements

Material	Usage	Requirements
Cement	In accordance with Mix Design, local supply	ASTM C150/C150M.
Water	In accordance with Mix Design, local supply	Potable.
Aggregate	In accordance with Mix Design, local supply	ASTM C33/C33M.
Reinforcing Steel, main	In accordance with detail design requirements	ASTM A615/A615M, Grade 60.
Reinforcing Steel, ties and stirrups	In accordance with detail design requirements. Typically, No. 4 (D13)	ASTM A615/A615M, Grade 60.
Forms	All exposed concrete surfaces (not flatwork)	Plywood or modular steel, dimensions to nearest inch.

Materials Application

Table 5-9 Materials Application Criteria

Member	Criteria
Suspended Slabs	Two-way reinforced; 3/4 inch (20 mm) minimum cover; 6 inch (150 mm) minimum thickness; steel trowel finish; spray with curing compound.
Structural Beams	Singly reinforced; 3/4 inch (20 mm) minimum cover interior, 1-1/2 inch (40 mm) cover exterior; beam width in 2 inch (50 mm) increments, minimum 8 inches (200 mm); beam depth in 2 inch (50 mm) increments, minimum 12 inches (300 mm); cured 3 days in forms.
Grade Beams	Singly reinforced; 1-1/2 inch (40 mm) cover; beam width in accordance with excavator requirements, minimum 8 inches (200 mm); void forms between pier supports, 4 inch (100 mm) minimum thickness.
Spread Footings	6 inch (150 mm) dimension increments for footing dimensions less than 9 feet (2,740 mm); 3 inch (75 mm) bottom cover on soil; 1-1/2 inch (40 mm) bottom cover on mudmat.
Special Massive Machine Foundations	1-1/2 inch (40 mm) cover; dimensions to nearest 2 inches (50 mm), unless specifically for machine interface as required; reinforced for surface crack control.

5.2.4 Steel Structures

Steel framed structures shall be designed in accordance with the AISC Specification for Structural Steel Buildings. In addition, steel framed structures shall be designed in accordance with the criteria discussed in the following subsections.

Materials

Construction of steel structures shall use materials as defined in Table 5-10.

Table 5-10 Structural Steel Materials

Material	Criteria
Structural steel wide flange and WT shapes	ASTM A992/A992M.
Structural steel channels	ASTM A992/A992M; ASTM A572/A572M, Grade 50; ASTM A36/A36M.
Structural steel S shapes	ASTM A36/A36M; ASTM A992/A992M; ASTM A572/A572M, Grade 50.
Structural steel angles and plates	ASTM A572/A572M, Grade 50; ASTM A529/A529M, Grade 50; ASTM A36/A36M.
Structural steel baseplates and plate over 4 inches thick	ASTM A36/A36M.
Hollow structural shapes, round, rectangular or square	ASTM A500/A500M, Grade C.
High Strength Bolts	ASTM A325, 3/4 inch, 7/8 inch, or 1 inch diameter, 1/4 inch increments of length, 1/4 inch increments on bolt diameter when different bolt sizes are used, fully-tensioned bearing type designed with threads included in the shear plane for all connections except where slip-critical connections are required. Connections with oversized holes or slots in the direction of load are slip critical. ASTM A325M, M20, M22, or M24, 5 mm increments of length, 4 mm increments on bolt diameter when different bolt sizes are used, fully-tensioned bearing type designed with threads included in the shear plane for all connections except where slip-critical connections are required. Connections with oversized holes or slots in the direction of load are slip critical.
Weld Filler Metal	70 ksi (485 MPa) tensile strength.
Atmospheric Corrosion-Resistant Steel	ASTM A588/A588M.
Extreme Corrosion-Resistant Stainless Steel	ASTM A167, type as required.
Guardrail and Handrail	Steel pipe 1-1/2 inch (38 mm) diameter, ASTM A53/A53M, Type E or S, Grade B; HSS 1.9 inch (48 mm) diameter, ASTM A500, Grade C; Guardrail only - Steel angles 2-1/2 x 2-1/2 x 1/4 inch (64 x 64 x 6.4 mm).
Kickplate (Toeplate)	Fabricated from ASTM A36/A36M plate 4 inches x 1/4 inch (100 mm x 6 mm).

Material	Criteria
Steel Grating	3/16 inch by 1-1/4 inch (5 mm by 32 mm) bearing bars, galvanized.
Anchor Rods, sized for design loads	ASTM F1554, Grade 36 , 1/2 inch (13 mm) increments of diameter.
Anchor Rods, sized for design loads and pretensioned	ASTM F1554, Grade 105, 1/2 inch (13 mm) increments of diameter.
Stair Treads	Steel grating, cast abrasive or bent checker plate nosings.
Metal Deck, roof	1-1/2 inch (38 mm) profile depth, 22 gauge minimum, galvanized.
Metal Deck, form	1 inch (25 mm) profile depth, 24 gauge minimum, painted or galvanized (composite deck form only).
Ladders	Fabricated from ASTM A36/A36M bar rails 3 inches x 1/2 inch (75 mm x 13 mm) with 3/4 inch (19 mm) diameter rungs.

Design

Construction of steel structures shall use design practices defined by local building codes, but not less than those defined in Table 5-11.

Table 5-11 Structural Steel Design

System	Criteria
Lateral Building Drift, rigid frame structures	(Story or building height)/100 under wind, ASCE 7 for seismic.
Lateral Building Drift, braced frame structures	(Story or building height)/200 under wind, ASCE 7 for seismic.
Vertical Bracing Members	Designed and detailed for concentric loading, unless analyzed for work point and shape eccentricity. Compression and tension capable, "pinned" at all connection points.
Horizontal Bracing Members	Designed and detailed for concentric work point loading and eccentric shape loading. Compression and tension capable, "pinned" at all connection points.

System	Criteria
Beams - Lateral-Torsional Buckling Brace Points	The following shall be considered as points of lateral-torsional stability bracing for beams: • Roof deck connections, Lb = 3 times deck fastener spacing • Floor deck connections, Lb = Lesser of 3 times deck fastener spacing or the actual shear connector spacing • Floor grating, welded connections--Use 1-inch (25 mm) fillet welds at 12-inch (300 mm) spacing (min.), add drawing notes to caution against removing grating, Lb = weld spacing • Horizontal truss panel point incident beams--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams axially aligned with horizontal truss panel points--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams connected to H-brace stability connections--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams connected to floor slabs or roof truss diaphragms--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams connecting three or more parallel beams, parallel beams have 20 percent or less difference in weight--Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum • Incident beams connecting two parallel beams--Verified by calculation only

System	**Criteria**
Columns - Lateral-Torsional Buckling Brace Points	The following shall be considered as points of lateral-torsional stability bracing for columns: • Incident beams connected to the space truss--Note for standard column sizes (W14 [W360] and smaller), incident beams connecting to the center of the column web restrain the column flanges against lateral buckling. For deep columns (W16 [W410] and larger), the incident beams may require special connections to restrain the column compression flange(s) against lateral movement. • Incident beams connecting three or more adjacent columns--Note for standard column sizes (W14 [W360] and smaller), incident beams connecting to the center of the column web restrain the column flanges against lateral buckling. For deep columns (W16 [W410] and larger), the incident beams may require special connections to restrain the column compression flange(s) against lateral movement. • Girts with flange braces
Beams - Major Axis Compression Buckling Brace Points	The major axis compression buckling points for beams shall occur only at the beam supports. Major axis unbraced length for beams, L_x, shall equal the beam span.
Beams - Minor Axis Compression Buckling Brace Points	The following shall be considered as points of weak-axis compression-buckling stability bracing for beams: • Horizontal truss panel points with or without incident beams • Incident beams axially aligned with horizontal truss panel points • Incident beams connected to floor slabs or roof truss diaphragms
Columns - Major and Minor Axis Compression Buckling Brace Points	The following shall be considered as points of compression-buckling stability bracing for columns: • Incident beams connected to the space truss • Incident beams connecting two adjacent columns--Verified by calculation only
Vertical Braces - Compression Buckling Brace Points	The following shall be considered as brace points for vertical bracing: • Buckling in the plane of the truss--"X-bracing" or single side strut • Buckling out of the plane of the truss--"X-bracing"
Unbraced Length, pipe bracing in ducts	$KL/r \leq 120$, checked for vortex shedding in flow and thermal restraint forces.
Deflection, floors and roofs, live load only	Span/360, vertical, unless attached to more rigid, brittle members.
Deflection, floors and roofs, dead and live load combined	Span/240, vertical.

System	Criteria
Deflection, girts	Span/180, horizontal. Span/240, vertical. When over or under glass, Span/360, horizontal. Span/960, vertical.
Deflection, crane and hoist support beams (without "impact")	Span/600, vertical; span/400, lateral.
Fixed ladder fall prevention (for OSHA compliant projects)	Ladders with the top rung more than 24 feet above a lower level will be provided with a fall prevention device. Ladders 24 feet or less above a lower level are not required to have fall protection.

5.2.5 Site

Grading and Drainage

Site grading and drainage shall be designed to comply with all applicable federal, state, and local regulations, and shall be integrated with existing site drainage systems so far as possible.

Roads

Road design component criteria are defined in Table 5-12.

Fencing and Security

The perimeter fence around the site boundary shall be woven wire. The perimeter fencing system shall include normally locked swing gates for access. The fence fabric shall be placed on the opposite side of the secure side of the fence.

Table 5-12 Site Design Component Criteria

Design Component	Criteria
Grading Slope, minimum	0.5 percent in main plant complex, or as appropriate for surface type, conveying storm runoff away from permanent facilities.
Roadway Linear Slope, maximum	8 percent unless Owner approves a steeper slope.
Finish Floor Relative Elevation	6 to 12 inches (150 to 300 mm) above 1 percent probability (100 year) storm event.
Culverts	Reinforced concrete, corrugated metal, or corrugated high density polyethylene (HDPE) pipes; reinforced concrete box where necessary.
Drainage Facilities and Water/Wastewater Storage Pond Storm Event, unless local code or regulations control	25-year, 24-hour rainfall event
Roads, main plant access	Two 10-foot (3.0 m) asphalt paved lanes, optional 3-foot (0.9 m) aggregate surfaced shoulders.
Roads, other than main plant access	Two 10-foot (3.0 m) aggregate surfaced lanes, no shoulders.

5.2.6 Foundations

General Criteria

Foundations shall be designed using reinforced concrete to resist the loading imposed by the building, structure, tanks, or equipment being supported. The foundation design shall consider the following:

- Soil bearing capacities.
- Deep foundation capacities.
- Lateral earth pressures.
- Allowable settlements, including differential settlements.
- Structure, equipment, and environmental loadings.
- Equipment performance criteria.
- Access and maintenance.
- Temporary construction loading.
- Existing foundations and underground structures including their current settlement conditions.

Foundations shall be designed using static analysis techniques assuming rigid elements and linear soil pressure distribution so that the allowable settlement and bearing pressure criteria are not exceeded. Foundations shall be proportioned so that the resultant of the soil pressure coincides as nearly as possible with the resultant of the vertical loading. The minimum factors of safety against overturning and sliding shall be 1.5. Factor of safety against sliding for retaining walls shall also be 1.5.

When using ASCE 7 load combinations that apply a 0.6 factor on dead load, the factor of safety for overturning and sliding is automatically set at approximately 1.67. For these special ASCE 7 ASD load combinations, the ratio of resisting forces (0.6 dead load) over driving forces (wind, seismic, or lateral loads) should be greater than 1.0 instead of 1.5.

Geotechnical exploration, testing, and analysis information shall be used to determine the most suitable foundation system. Elastic (short-term) and consolidation (long-term) foundation settlements shall be calculated and limited to the following approximate design values except where loading onto or differential settlements relative to existing structures may require more conservative criteria:

- Total settlement: 1-1/2 inches (38 mm).
- Differential settlement: 0.1 percent slope between adjacent column support points.

Allowable settlement is higher for tanks. These settlements will be calculated on an individual basis.

Special Foundation Requirements for Chimneys and Stacks

The foundation component for the chimneys and stacks shall be a circular or polygon shaped pier, pile, or ground supported, reinforced concrete foundation. The foundation shall be proportioned so that the bearing and allowable settlement criteria shall not be exceeded, with no uplift permitted and no increase in allowable bearing for wind load for soil supported foundations. For pile supported foundations, uplift on piles is allowed. Design settlement, elastic plus consolidation, shall be limited to approximately 1-1/2 inches (38 mm) for soil supported foundations.

Special Foundation Requirements for Rotating Equipment

The foundation systems for major rotating equipment shall be sized and proportioned so as not to exceed the bearing and settlement criteria, and to ensure satisfactory performance of the equipment. In addition to a static analysis, a dynamic analysis may be performed to determine the fundamental frequencies of the foundation system for selected major rotating equipment as determined necessary by Black & Veatch. To preclude resonance, fundamental frequencies of the foundation associated with rigid body motion shall be 25 percent removed from the operational frequency of the equipment. Should the foundation system not meet these criteria, a balance quality grade, appropriate for the equipment, will be determined from ISO 1940, Balance Quality Requirements of Rigid Rotors - Part 1. The dynamic behavior of the foundation will be evaluated for this level of unbalance and compared to ISO 10816, Mechanical Vibration-Evaluation of Machine Vibration by Measurements on Nonrotating Parts, Parts 1 through 6. The resultant vibration level shall not exceed the limit for evaluation of this standard. Where required, the foundation shall also be designed to meet manufacturer's requirements.

Foundation Design Criteria

Foundations to be designed per the Geotechnical Services Report for Cholla Power Plant.

Equipment Bases

All equipment shall be supplied with an equipment base suitable for its operation. Where the equipment could induce vibration problems, the base shall have adequate mass to dampen vibration motions. Special consideration shall be given to vibration and stiffness criteria where specified by an equipment manufacturer.

Equipment bases may be concrete or an integral metal skid. Concrete bases shall have minimum temperature and shrinkage reinforcing; unless it is determined that additional reinforcement is required for the equipment loads.

Insulation

When required by the local code, foundations and below grade portions of space-conditioned buildings above those foundations shall be insulated.

5.2.7 Bulk Material Handling

General

For enclosed structures that are part of the bulk material handling processes that may generate combustible dust including, but not limited to, transfer towers, and tripper areas, the Client is expected to maintain the facility such that combustible dust accumulation is kept below the minimum levels that would require explosion venting, such as relief panels, in accordance with NFPA 654.

All electrical and control devices located in areas made hazardous by the presence of combustible dust or explosive gas shall be suitably rated for the hazardous area in accordance with the requirements of the NEC and the National Electrical Manufacturers Association (NEMA). Safety standards for conveyors and related equipment (ANSI/ASME B20.1) shall be incorporated into all conveying equipment.

Belt Conveyors

Belt conveyors and components shall generally conform to the basic engineering data provided by CEMA. Generally, CEMA data is presented in the book Belt Conveyors for Bulk Materials.

Drag Chain Conveyors

Drag chain conveyors and components shall generally conform to the basic engineering data provided by CEMA. Drag chain conveyors are completely enclosed conveyors which drag the material along the bottom by chains with flights attached to them.

Hoppers

Hoppers shall be provided where required for bulk material unloading or reclaim, for short term bulk material storage or surge capacity, or for bulk material flow and distribution purposes. Hoppers provided for bulk material testing of belt scales shall be sized in accordance with CEMA. Live bottom hoppers will be required. Reclaim hoppers will normally be located with the top of the structure at a higher elevation than surrounding grade to minimize precipitation runoff into the hopper. Mobile equipment will be expected to maintain the grade around the hopper so that drainage is away from the hopper at all times.

Belt Scales

Belt scales shall be of the digital electronic type. Each belt scale will be used for one or more of the following purposes, as deemed necessary by the Engineer:

- Certified belt scales will be used for weighing bulk materials and providing total quantities to be used as a basis of payment or other commercial service.
- Belt scales will be used for in-plant inventory determination by weighing bulk material receipts and usage.
- Belt scales will be used for process control or monitoring (such as monitoring conveying rates to preclude overloading, controlling blending ratios, and similar applications).

Certified belt scales shall be designed, located, and installed on acceptable conveyors in accordance with the requirements of NIST Handbook 44 and any local weights and measures regulations and/or railroad requirements.

Dust Control

Control of indoor and outdoor fugitive dust emissions shall be provided for all bulk materials handling systems.

Diverter Gates

Gates shall be provided as required for one or more of the following reasons:

- For diverting or splitting material flow as it passes through a material handling system.
- For cutting off material flow for maintenance or other reasons.
- For cutting off material flow and permitting water drainage from material in exposed hoppers.

Chutework

Enclosed chutes shall be designed to transfer materials between conveyors, feeders, hoppers, and silos.

Magnetic Separators

In-line, self-cleaning magnetic separators may be provided at the head chutes of conveyors after unloading or reclaim operations to protect hammermills or shredders, if necessary. Chutework to direct tramp metal to grade shall be provided, along with a collection bin designed with wheels for moving to a nearby truck or dump area, or with slots for forklift transportation.

Drum Dryer

The drum dryer is provided to reduce or minimize the moisture content of the woody biomass by direct or indirect contact with waste heat.

Screw Feeders

Variable rate screw feeders shall be used as required to control the volumetric flow of bulk materials from receiving, reclaim, and surge hoppers. The screw feeder provides enclosed transfer while moving materials horizontally, vertically, or at an incline. The screw feeder can also convey materials from one or more inlet points to one or more outlet points. The flow rate will be adjustable if required for one or more of the following reasons:

- To compensate for varying material usage or acceptance rates (such as to a hogger where the hogging rate deteriorates with wear).
- To allow differing fuel blending ratios.
- To compensate for varying operating methods or requirements.
- To compensate for varying material densities or moisture contents.
- To compensate for varying unit load and fuel characteristics.

Hammermills

The Hammermills are a grinding machine that will reduce woody biomass particles in size by repeatedly pounding them into smaller pieces through a combination of tensile, shear and compressive forces. Hammermills will continually hit the material often enough to break it into the piece size desired, usually with high speed rotating hammers.

Disc Screen

The disc screen is provided to screen and separate woody biomass which tends to knit together. The disc screen must accommodate both average and surge flows. The capacity of the disc screen is dependent on the percentage of screen open area. The disc screen consists of a series of driven shaft assemblies mounted within a frame. Each motor shaft assembly has profiled discs mounted at regular intervals. The discs interleaf with those on the adjacent shafts which creates open areas between the discs and the shafts.

Truck Dumper Reclaimer

A hydraulically-actuated truck dumper deck is used to remove woody biomass from haul trucks by tilting the entire truck at various angles of tilt. The angles of tilt can be either 36, 45, 55, or 63 degrees with respect to the horizontal.

Stacker/Reclaimer

A circular stacker/reclaimer is a large machine that can stack and reclaim woody biomass alternatively or simultaneously and build a ring-shaped stockpile. The function of the stacker is to pile woody biomass on to a stockpile. The reclaimer is used to recover the woody biomass from the stockpile.

Fly Ash Conveying

Fly Ash will be collected either in the existing PJFF bag house or a new Cyclone. Once it's captured, the existing conveying system would be reused to convey from the PJFF bag house/Cyclone to the fly ash silo's as its currently done with the coal ash. It's not expected to have to modify the fly ash conveying system in the conversion from coal to woody biomass as the ash generation rate is lower with woody biomass.

Bottom Ash Conveying

It's expected that the existing bottom ash sluicing system will continue to be reused for the woody biomass bottom ash.

6.0 Mechanical Design Basis

6.1 BOILER MODIFICATION CRITERIA

6.1.1 Biomass Delivery to Boiler

Due to the significant differences between biomass and pulverized coal, modifications to the fuel delivery system would be required. The biomass would be crushed to a nominal diameter of 0.2 inches and dried prior to being introduced into the boiler. New hammer mills would be provided for this purpose, and after crushing and drying, the biomass would be sent to a silo. The silo would be primarily intended as a surge bin for providing a consistent feed of biomass, as opposed to a storage silo providing multiple days' worth of feed.

The biomass would be delivered to the boiler from the silo, through the existing pulverizers. All of the equipment from the hammer mills up to the pulverizers would be new. See Section 5.2.7 for further descriptions of the equipment. Pneumatic conveying was considered for delivering biomass to the boiler, but the feed would not be consistent enough.

6.1.2 Burner Replacements

The existing coal burners would need to be replaced with natural gas burners. The natural gas burners would be installed at the same level as the coal burners, with the coal burners either being isolated or removed. The heat input provided by the natural gas should be sufficient to combust the biomass, so no additional burner modifications should be required

6.1.3 Fan Modifications

The existing the primary and secondary air fans should be able to accommodate slight differences in performance requirements, so no modifications are expected with these fans. However, the flue gas leaving the boiler is expected to be hotter have more mass when burning biomass than coal. The induced draft (ID) fans are expected to experience an almost a ten percent increase in flue gas volume. Higher volumetric flow rates will result in greater pressure drops as well, so the ID fans will need to provide more pressure to the draft system at a higher flow. There is chance that the ID fans will need to be upgraded, or the draft system be provided with booster fans. Further detailed evaluation is required to make this determination.

6.2 AIR QUALITY CONTROL MODIFICATION CRITERIA

6.2.1 Baghouse

Unit 1 currently has a fabric filter installed for particulate control, and they should be able to continue to operate after the fuel change. However, the fabric filter's bags would be susceptible to damage from hot coals (biomass that hasn't been completely combusted), so a cyclone upstream of the fabric filter to collect heavier materials, such as unburned biomass, could be required. An alternative to the cyclone would be replacing all of the current bags with ones that are flame resistant.

6.2.2 Scrubber

Due to the low sulfur content of the biomass, it is expected that the existing wet flue gas desulfurization (WFGD) on Unit 1 would be able to accommodate the fuel change. It's possible that the WFGD could be decommissioned if the biomass' sulfur emissions were low enough. The projected SO_2 emissions when burning biomass is expected to be well below the facility's current limits, but a permit evaluation would be needed to determine if the new emissions are sufficiently lower to decommission the WFGD. If the WFGD were no longer in operation, the stack's steel liner (Incoloy 27-7) should be able to withstand the hotter temperatures.

6.2.3 Powdered Activated Carbon (PAC)

Due to no mercury in the biomass and natural gas, the PAC system can be decommissioned.

6.2.4 NOx

An increase in NOx emissions can be expected with the fuel change, but it's possible that with co-firing natural gas, the increase is minimized. Currently, there is no post-combustion NOx control at Unit 1, so further investigation is required to determine if such a system is required. Potential options include a selective catalytic reduction (SCR) system or selective non-catalytic reduction (SNCR).

6.2.5 Continuous Emissions Monitoring System Modifications (CEMS)

Changes in the fuel supply may warrant modifications to the existing CEMS equipment. For example, due to the lower sulfur content, any SO2 CEMS can be decommissioned. NOx and CO CEMS may need to have their spans readjusted while using the same analyzer, but depending on the analyzer, a new one may be required. It is also expected that the change in fuel will introduce new flue gas constituents which are not currently accounted for in the air permit, thereby requiring a modification to the existing air permit. Any required modifications to CEMS equipment shall be in compliance with the Environmental Protection Agency (EPA) Code of Federal Regulations (CFR) Part 60 and Part 75, and in compliance with Arizona Department of Environmental Quality (ADEQ) and the air permit. Any fuel flow transmitters, whether existing or new, measuring natural gas flow used in supplemental firing of the boiler, shall be supplied with flow certifications from a qualified flow laboratory. Certification to meet EPA 40 CFR PART 75 Appendix D Section 2.1.5 Initial Meter Certification

6.3 DESIGN CRITERIA

6.3.1 Piping, Components, and Accessories

The requirements for piping, components, and accessories are shown in Table 6-1 by system/process.

Table 6-1 Piping, Components, and Accessories Requirements

Flui d Code	Power Syste m Code	System/Proces s Area	Flange Rating (B16.5)	Pipe Materia l	Special Requirements	Post-Weld Heat Treatmen t (PWHT)	Notes
	CAA	Compressed Air	150	304L	Vic-Press for Small-bore		G01
AI	CAB	Instrument Air	150	304			G01

Fluid Code	Power System Code	System/Process Area	Flange Rating (B16.5)	Pipe Material	Special Requirements	Post-Weld Heat Treatment (PWHT)	Notes
GN2	PMB	Nitrogen	150	CS			G01, G04, G08, 902
GC02		Carbon Dioxide	300	CS		B31.1	G01
GF	FGA	Fuel Gas	150, 300	CS	Fire safe		G01
WU	WSA	Utility Water	150	CS			G01, G04, G08, 902
WU	WSA	Utility Water (U/G)	200 psi	HDPE 4710			G01, 501, 505
FPW	STG, WSE	Fire Protection	150	CS	UL/FM Approved - VICTAULIC		G01, 702, 902
WF	STG	Fire Protection (U/G)	200 psi	HDPE 4710	31PFNF: UL/FM Approved/11PFNF : AHJ to be consulted for fire water application		G01, 501, 503, *Allowable Stresses for PE4710 pending approval of the AHJ.

Notes in Table 6-1 are as follows:

- G01 – Addition or substitution of components (material A vs. material B, welded vs. seamless, etc.) in this piping class requires approval from the piping engineer.
- G04 - Threaded components are permitted only at outlet of vent, drain, and instrument valves and to match equipment.
- G08 - Component wall thickness and end preparation type to be the same as the pipe.
- 501 - Pipe and fittings to be manufactured to iron pipe size (IPS) dimensions. Pipe, fittings, and branches shall be joined per ASTM F2620, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings" and the "PPI Handbook of Polyethylene Pipe Joining Procedures."
- 503 - HDPE pipe, fittings, flanges, and gaskets in fire protection water service shall be FM Approved for Fire Protection use.
- 505 - Pipe, fittings, and branches shall be joined in accordance with ASTM D2657, "Standard Practice for Heat Fusion Joining of Polyolefin Pipe and Fittings", and the "PPI Handbook of Polyolefin Pipe Joining Procedures".
- 702 - Pipe, fittings, flanges, gaskets, and valves shall be UL Listed or FM Approved for fire water service.
- 902 - A106-B pipe is an acceptable substitute for A53-B pipe. As applicable, seamless fittings are acceptable substitutes for welded fittings.

6.3.2 Valves

The valve selection criteria are shown in Table 6-2 by system/process and the short-hand acronyms and type classifiers used in this table are identified in the associated legend present in Table 6-3.

Table 6-2 Valve Selection Criteria

	Isolation				Throttling				Vent		Drain	
	≤ 2"		≥ 2.5"		≤ 2"		≥ 2.5"					
	Type	Ends	Type	Ends	Type	Ends	Type	Ends	Type	Ends	Type	Ends
Natural Gas	B P	SW	B P	BW FLG	T F B	SW FLG	T F	BW FLG	B P	SW	B P	SW
Compressed (Station) Air	B	P-FIT	G	BW FLG	T	P-FIT FLG	T F	BW FLG	B	P-FIT SCRD BR	B	P-FIT SCRD BR
Instrument Air	B	P-FIT	G	BW FLG	T	P-FIT FLG	T F	BW FLG	B	P-FIT SCRD BR	B	P-FIT SCRD BR
Nitrogen	B	P-FIT SCRD BR	G	BW FLG	T	P-FIT SCRD	T F	BW FLG	B	P-FIT SCRD	B	P-FIT SCRD BR
Carbon Dioxide	B	P-FIT SCRD	G	BW FLG	T	P-FIT SCRD	T F	BW FLG	B	P-FIT SCRD	B	P-FIT SCRD
Service Water	B G T	P-FIT SW	F G	WFR FLG	T	P-FIT SCRD SW	F T	WFR FLG BW	B G T	P-FIT SCRD SW	B G	P-FIT SCRD SW
Fire Protection Water	G	SCRD	G	FLG	T	SCRD	T	BW FLG	G	SCRD	G	SCRD
Fire Protection Water (U/G)	G	SCRD	G	FLG	T	SCRD	T	BW FLG	G	SCRD	G	SCRD

Table 6-3 Legend for Table 6-2

Type		Ends	
B	Ball	WFR	Wafer or Lug Wafer
G	Gate	FLG	Flanged
T	Globe	BW	Butt Welded
Y	Y-Pattern Globe	SW	Socket Welded
P	Plug	SCRD	Threaded
F	Butterfly	P-FIT	Victaulic Press Fit
		BR	Brazed

6.3.3 Coatings

External Coatings

External coatings are described in Table 6-4 by equipment type and design temperature.

Table 6-4 External Coating Descriptions

Section	Description	Design Temp (°F)	Coating System
1.0	Pipe and Pipe Supports		
1.1	Carbon Steel		
1.1.1	Uninsulated	≤200	Epoxy (EPS)/ Epoxy (EPS)/ Polyurethane (URA)
1.1.2		>200 ≤1,000	Inorganic Zinc (IZ)/ Silicone Acrylic (SLA)
1.1.3	Insulated	>25 <350	Epoxy Phenolic (EPP)/ Epoxy Phenolic (EPP)
1.1.4		>300 (>149)	Alkyd (ALK) [NOTE 1]
1.2	Stainless Steel		
1.2.1	Uninsulated	All	No coating
1.2.2	Insulated	>120 <350	Epoxy Phenolic (EPP)/ Epoxy Phenolic (EPP) [NOTE 2]
1.2.3		>350 <120	No coating
2.0	Tanks, Drums, Columns, Vessels, Reactors, and Shell and Tube Heat Exchangers - Shop Fabricated		
2.1	Carbon Steel		
2.1.1	Uninsulated	≤200	Epoxy Zinc (EPZ)/ Epoxy (EPS)/ Polyurethane (URA)
2.1.2		>200 ≤1,000	Inorganic Zinc (IZ)/ Silicone Acrylic (SLA)
2.1.3	Insulated	>25 <350	Epoxy Phenolic (EPP)/ Epoxy Phenolic (EPP)
2.1.4		>350	Alkyd (ALK) [NOTE 1]
2.2	Stainless Steel		
2.2.1	Uninsulated	All	No Coating
2.2.2	Insulated	>120 <350	Epoxy Phenolic (EPP)/Epoxy Phenolic (EPP) [NOTE 2]
2.2.3		>350 <120	No Coating
3.0	Bulk Valves, Fittings, Pumps, Compressors, Rotating Equipment, and Other Mechanical Equipment Not Specified Otherwise	All	Q301 Manufacturer's Standard Coating for the intended ISO 12944 C4 environment.

Section	Description	Design Temp (°F)	Coating System
NOTES 1. Alkyd (ALK) coating is provided for short-term corrosion protection during shipping, storage, and construction. No coating is required if the time interval between shipment and startup is less than 24 months. 2. Applicable to 18-8 austenitic stainless steels, e.g., 304 and 316, and duplex stainless steels. Coating is not required for higher alloyed materials.			

Internal Coatings

Internal coatings and cleaning requirements are described in Table 6-5 by system/process type.

Table 6-5 Internal Coatings and Cleaning Methods

System Name	Piping Fabrication Cleaning Method	Post-Fabrication Preservative or Coating Option
Fuel Gas	SP6 – Commercial Blast Cleaning	Vapor phase corrosion inhibitor (water soluble preservative)
Compressed Air (Station Air)	No special cleaning required	None
Instrument Air	No special cleaning required (SS) SP6- Commercial Blast Cleaning (CS)	None (SS) Vapor phase corrosion inhibitor (water soluble preservative) (CS)
Nitrogen	No special cleaning required	None
Carbon Dioxide	No special cleaning required	None
Service Water	SP3 – Power Tool Cleaning	None
Fire Protection	No special cleaning required	None

6.3.4 Insulation, Jacketing, and Lagging

Insulation and lagging will be applied to equipment, piping, valves, specialties, and ductwork as shown in Table 6-6. Insulation material for piping will be mineral fiber (Type II, per ASTM C547), and jacketing material will be stucco-embossed aluminum. A minimum jacketing thickness of 0.016 inch will be used. Insulation and lagging will be designed for conditions of 75° F ambient, emissivity of 0.09, no incident solar heating, and 2 mph airflow velocity, for a normal operating calculated surface temperature of 150° F using the method defined in ASTM Standard C680. For pipe and equipment with an operating temperature of 600° F or higher, two layers of insulation with fully staggered offset joints/seams will be used.

Table 6-6 Insulation and Lagging Requirements

Max. Op.	Nominal Insulation Thickness (in.) vs. Nominal Pipe Diameter (in.)										
Temp.	**0.50**	**0.75**	**1.00**	**1.25**	**2.00**	**2.50**	**3.00**	**4.00**	**6.00**	**8.00**	
1,000	2.00	2.50	2.50	3.00	3.00	3.00	3.50	4.00	4.50	4.50	
800	1.50	1.50	1.50	1.50	2.00	2.00	2.50	2.50	3.00	3.00	
600	1.00	1.00	1.00	1.00	1.50	1.50	1.50	1.50	2.00	2.00	
500	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.50	1.50	
400	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
300	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
200	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Max. Op.	**Nominal Insulation Thickness (in.) vs. Nominal Pipe Diameter (in.)**										
Temp.	**10.00**	**12.00**	**14.00**	**16.00**	**18.00**	**20.00**	**22.00**	**24.00**	**30.00**	**36.00**	**48.00**
1,000	5.00	5.50	5.50	6.00	6.00	6.00	6.00	6.50	6.50	7.00	7.50
800	3.50	3.50	3.50	4.00	4.00	4.00	4.00	4.00	4.50	4.50	5.00
600	2.00	2.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50	3.00	3.00
500	1.50	1.50	1.50	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
400	1.00	1.00	1.00	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
300	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
200	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

The following specific situations may deviate from the above guidelines:

- Pipe, tubing, and valves over 150° F, but that are not accessible (not within seven feet vertically or three feet horizontally) to personnel during normal operations and that do not require heat loss prevention, need not be insulated. Examples are hot drain piping, vent stacks, vents, compressed air and gas lines, sulfur trioxide lines, and similar items selected by Black & Veatch.
- Anti-sweat insulation shall be applied to piping, equipment, and ductwork where ambient and process temperature creates a potential for condensation on the exterior surface.
- Piping, tubing, instruments, and equipment requiring freeze protection as indicated in Section 6.3.5.

6.3.5 Freeze Protection

Freeze protection design criteria are shown in Table 6-7.

Table 6-7 Freeze Protection Design Criteria

Main Design Criteria	
Minimum Ambient Temperature	-5.6 °F
Wind Speed	31.2 mph
Maximum Pipe Radius Frozen	10%
Acceptable Time to Freeze (Plant operators must drain stagnant piping systems within this time frame)	8 hours
Pipe Insulation Criteria (Liquid Service Only)	
1-inch NPS-14-inch NPS	1-inch Insulation
>14-inch NPS	No Insulation
Electric Heat Tracing Criteria (Piping Exposed to Freezing Conditions)	
≤2-inch NPS	Insulated and Heat Traced
≥ 2-1/2-inch NPS	None

6.3.6 Process Temperature Maintenance

Piping systems requiring insulation for temperature maintenance to maintain viscosity shall be provided with Electric Heat Tracing and Insulation.

6.3.7 Space Conditioning

No space condition design is required. All new structures are open-air with no heating, ventilation or air conditioning required.

6.3.8 Fire Protection

The new woody biomass handling, storing and processing equipment will require fire protection. This will be provided by modification of the existing plant fire protection system and addition of new fire protection equipment.

Deluge fire sprinkler systems are envisioned for all biomass fuel conveyors, whereas dust collectors in the biomass handling areas are expected to be equipped with preaction sprinklers. Major material handling equipment (for example: Dryers, Hammermills, etc.) shall be equipped with appropriate code compliant fire protection measures provided by the Equipment Supplier. Biomass handling vessels shall be equipped with deflagration venting and explosion prevention measures. Fire suppression within biomass handling vessels where the woody biomass is expected to have significant residence time is expected to be provided by carbon dioxide (CO_2). An outdoor (3.5 ton) CO_2 tank storage tank, along with a CO_2 refrigeration/vaporization skid is anticipated to be installed to the east of the Unit 1 powerhouse. Additionally, an underground fire water supply piping loop, along with post-indicator valves, hydrants and above-ground valve houses is anticipated in the fuel handling yard.

The preliminary requirement for fire water for the new material handling equipment is estimated to be 3,500 gpm. Two redundant (100 percent) field-erected fire water tanks with a working capacity of 420,000 gallons (each), as well as two main fire water pumps and a jockey pump are anticipated to be installed to the north east of the fuel handling yard.

All equipment provided for the fire protection system shall be UL listed/FM approved and shall be compliant with the applicable NFPA codes.

7.0 Electrical Design Basis

7.1 DESIGN CRIERTIA

7.1.1 Electrical Power Available at Battery Limits

The new plant electrical system design is dictated by the existing plant distribution system and project overall one-line diagram, as provided by plant personnel. The system voltage levels and design shall be according to the project one-line diagram and the below.

- Generation: 13.8kV, 60Hz, 3-Phase.
- MV Distribution 4.16kV, 60Hz, 3-Phase.
- LV Distribution 480V, 60Hz, 3-Phase.

New electrical loads within the existing main plant area will be fed from existing busses where practical. The new material handling area planned for installation in the existing coal yard will be served by new electrical distribution equipment. This will consist of 4.16kV switchgear, 4.16kV motor control centers, 480V switchgear, 480V MCCs, transformers, and other lower level distribution equipment as needed. The new 4.16kV switchgear will obtain two redundant feeds from existing 4.16kV medium-voltage busses. The new switchgears will be double ended, with feeds or transformers capable of serving the entire switchgear load from one source with the tie breaker closed and one main breaker open. Refer to the project one-line diagram for further details.

7.1.2 Electric Motors

Motors shall be purchased with the driven equipment, and be in accordance with NEMA MG1 and the following:

- MV Motors: 4000V, 250HP and larger, 1.0 service factor, class B temp rise, class F insulation.
- LV Motors: 460V, ½ to 249HP, 1.0 service factor, class B temp rise, class F insulation.
- Single-Phase Motors: 120V, Up to 1/3 HP.

7.1.3 Uninterruptible Power Supply, Battery Systems, and Emergency Power

Critical plant AC and DC loads will be powered from an uninterruptible power system (UPS) or battery system. The UPS will power items such as DCS, programmable logic controllers (PLCs), network equipment, and critical instruments and equipment. The battery system will power items such as switchgear relays and operational power, UPS, and critical motors.

Unit 1 has an existing DC and UPS system. Depending on new loading and location, the intent would be to utilize the existing system. If it is not able to be utilized a new DC battery and UPS will be provided as follows:

- Duty Cycle: 2 hours.
- DC Battery: 125VDC.
- UPS: 120VAC, 1-phase.

The existing emergency generation system will serve emergency power.

7.1.4 Classification of Hazardous Areas

Hazardous area classification is determined by the Electrical Project Discipline Engineer, according to NFPA and other applicable codes. The Mechanical Project Discipline Engineer is responsible for space control and life safety issues. This will be addressed once equipment layout has been determined.

7.1.5 Grounding

The plant grounding system will follow the recommendations of the NEC.

- Bare copper grounding conductor, insulated where installed in conduit.
- Copper-clad, ¾ inch x 10-foot section ground rods.
- Exothermic junction bonding method.

7.1.6 Lightning Protection

The plant is in a location of relatively low number of thunderstorm days per year, however, lightning protection will be provided on any new large buildings. The system will consist of air terminals, interconnecting conductors, down conductors with connection to the grounding system, and bonding of metal objects on or within the structure. Conductors shall be copper.

7.1.7 Lighting

Lighting systems shall be as follows:

- Office, control room, and electrical rooms shall be LED.
- Indoor high bay, outdoor platforms, outdoor above doors, hazardous areas, and any roadway lighting shall be high-pressure sodium.
- Emergency lighting shall be provided for egress utilizing integral fixture battery packs.
- Outdoor lighting shall be controlled by photoelectric controllers and control switch.

7.1.8 Wiring and Raceways

Ampacities of cable in cable tray are based on NFPA-70 (NEC). The following cable types may be grouped in common cable trays with other cables of the same type:

- Medium voltage
- 600-volt power
- Control
- Instrumentation analog.

Cable construction shall be as shown in Table 7-1.

Table 7-1 Cable Construction

Voltage Level/Application	Minimum Cable Construction
Medium Voltage Power	1/c EPR insulation, copper tape- shielded, FR-PVC jacket, 133% insulation
Low Voltage Power	1/c FR-XLPE insulation without jacket (RHH/RHW-2/USE-2) or 3/c XLPE or EPR insulation, FR- PVC jacket
Low Voltage Control	XLPE or EPR insulation, FR-PVC jacket
Instrument - 300 V	PVC or PVC/Nylon insulation, FR- PVC jacket

Instrument Thermocouple Extension Wire - 300 V	PVC insulation, FR-PVC jacket
Grounding	Bare conductor or 1/c THHN/THWN, green insulation
Lighting - Interior at 120 V	1/c THHN/THWN insulation
Lighting - Exterior and interior greater than 120 V	1/c XHHW-2 insulation
Note: Special application cables are not listed.	

Raceway materials shall be as shown in Table 7-2:

Table 7-2 Raceway Materials

Raceway System	Material/Construction
Duct Bank (horizontal runs)	PVC Type DB or Schedule 40 RGS (when required for shielding) 2-inch separation between tubes
Duct Bank Risers (all tubes including elbows)	RGS
Cable Tray - Ladder	Aluminum
Cable Tray (wet or corrosive areas)	Aluminum or fiberglass
Conduit (general purpose)	
Conduit	RGS
Lighting and Communication Circuits (indoors, nonhazardous locations)	EMT
Circuits (outdoors, hazardous locations)	RGS
Direct Buried PVC (underground)	PVC Schedule 40
Conduit Fittings	RGS - Malleable iron

7.1.9 Plant Communication

Communications shall be as follows:

- An extension of the existing plant emergency paging system with speakers.

7.1.10 Electrical Freeze Protection and Temperature Maintenance

Piping freeze protection and temperature maintenance systems may be required for outdoor piping, instruments, and equipment devices subject to cold weather. In the cases where it is needed, heat trace control panels and respective power transformers will be provided in strategic areas to serve this need. Refer to section 6.0 Mechanical Design Basis for further information.

8.0 Instrumentation and Controls Design Basis

8.1 DESIGN CRITERIA

8.1.1 Control Design Criteria

The following general design criteria shall be followed:

- Controls shall be designed for single failures, not simultaneous multiple failures.
- Automatic modulating controls may be utilized to reduce the need for operator attention to modulating control functions (except for manual/auto selections, set point changes, biasing and similar actions) during normal operation.
- Automatic sequences may be utilized to control groups of equipment that are started or stopped by the operator with a single initiating action or by a command from other logic. The control system verifies that any prerequisite conditions have been met and then automatically steps through the operating sequence.
- Control transfers between automatic and manual operation shall be bumpless and without need for operator action.
- Individual equipment shall be protected against abnormal conditions such as temperature, pressure, level, and flow. This logic shall be incorporated into the equipment discrete control as permissives and interlocks.

8.1.2 Control Hardware

The existing coal yard primary control system is a PLC based system. However, since it is part of existing coal handling equipment and much of it would need to be demolished with the coal handing equipment it will need to be replaced. New input/output (I/O) hardware will be utilized, and the new PLC equipment and programming labor will be provided by the material handling system vendor. The material handling PLC vendor will also assist to coordinate integration into the existing Boiler DCS. It is expected this can be accomplished with a small number of interlocks. Modifications to the DCS equipment and programming activities for the DCS modifications, need be by the DCS vendor representative for the current boiler DCS.

The new plant control system equipment is to be located in the following plant areas:

- Electrical Equipment Room if not attached to new biomass handling equipment
- Attached to the new Biomass handling equipment as supplied by the material handling equipment vendor.

These areas will be utilized, to the extent possible, for any new control hardware.

Analog Signals

Analog signals shall be of the following standard ranges:

- 4-20 mA dc
- Thermocouple (Type E or Type K)
- RTD

Digital Signals

Digital signals shall be of the following standard voltage levels:

- 48 V dc
- 120 V ac
- 125 V dc

Instrument contacts used for alarming and interlocking shall be rated to meet the interface system load requirements. Control system output contacts shall be rated to meet the driven system/equipment load requirements.

8.1.3 Instruments and Final Control Devices

The following general design criteria shall be followed:

- Instrumentation shall be tagged with a nametag or nameplate provided the device it is mounted to is not tagged.
- Instruments shall be factory calibrated where feasible.
- All instrumentation shall be designed to withstand the environment at their mounting location or shall be suitably protected.

Vendor package instrumentation shall be supplied and tagged in accordance with the vendor's standard. Instrument housings shall be in accordance with NEMA (or other project-designated authority) ratings.

Thermowells and Protecting Tubes

Fluid system temperature sensors shall be equipped with thermowells. Refer to Table 8-1.

Table 8-1 Thermowells and Protecting Tubes

Design Parameter	Project Design Basis
Thermowells	
Design Standards	ASME PTC19.3 - Temperature Measurement. ASME B31.1 - Code for Pressure Piping (Power). ASME Section VIII, Div. 1 - Boiler & Vessel Code.
Length	In accordance with PTC, or more than 3 inches, but not beyond the pipe center line. Thermowells to be left in place during steam blow are subject to special design considerations.
Materials	Same as pipe material for welded or threaded thermowells on P91, P22, P11, and stainless-steel pipe systems. Carbon steel for welded thermowells on carbon steel pipe. 316 stainless steel for all threaded thermowells on carbon steel pipe.
Installation	Perpendicular to pipe for all line sizes; lines smaller than 3 inches require a short section of expanded 3-inch pipe to accommodate thermowells. Thermowells in steam piping may be permanently installed prior to steam blow. All thermowells shall be installed before hydrostatic or in-service leak testing. If used, threaded wells are to be engaged and seal welded in accordance with ASME B31.1.
Special Analysis	Thermowells to be installed in main steam, hot and cold reheat steam, auxiliary steam, extraction steam, and feedwater piping services must be analyzed for vortex-induced vibration.
Systems Provided with Test Wells	Main steam, reheat steam, extraction steam, feedwater, condensate, and other piping required to meet ASME or project- designated test requirements.

Design Parameter	Project Design Basis
Protecting Tubes	
Service	Temperature detectors installed in boiler gas and air ducts.
Material and Size	Type 316 stainless steel, minimum 1-inch pipe. Alternate materials for downstream of wet scrubbers: Yoloy, 316L SS, or 446 SS.

Thermocouples and Resistance Temperature Detectors

Project temperature measurements for remote use shall be by temperature detectors; preferably temperature detectors shall be thermocouples with conversion in the PLC, although RTDs may be used as required. Temperature detection elements are single element type, ungrounded.

Temperature Detector	Characteristics
Thermocouple below 900° C (1,652° F)	Type E, standard limits of error.
Above 900° C (1,652° F)	Type K, standard limits of error.
Resistance temperature detectors (3 wire)	100-ohm, platinum.

Temperature transmitters may be utilized when a low concentration of temperature inputs in a particular area does not justify a temperature input card in the PLC. In such cases, smart temperature transmitters with 4-20 mA output should be selected.

Transmitters

Transmitters shall provide the required signals for control and remote monitoring. Transmitters shall be 2-wire, capable of driving a 750-ohm load, and designed with provisions for zero and span adjustments. In general, transmitters will be "smart" and capable of interfacing with a handheld HART calibrator. Vendor packages will be the vendor's standard offering. Refer to Table 8-2.

Table 8-2 Transmitters

Measurement Type and Application	Project Design Basis
Static Pressure	Capacitance, piezo-resistive, or resonant frequency, equipped with a single-valve manifold (with plugged vent, if available).
Differential Pressure	Capacitance, piezo-resistive, or resonant frequency, equipped with a three-valve manifold.
Note 1: Manifolds are to be constructed and tested to ASME B31.1.	
Level	
Atmospheric Vessels	Open path radar.
Hoppers, Feeders, Basins, and Other Special Applications	Open path radar.
Flow (Differential Pressure)	
Where Flanged Construction and Higher Pressure Loss is Acceptable	Orifice plates.

Measurement Type and Application	Project Design Basis
Fan Inlet and Large Pipes or Ducts (where installation of other sensors are impractical)	Annubars, piezometer rings, or pitot tubes.
Note 2: Flow measurement square root functions shall be done in the PLC.	
Flow (Non-differential Pressure - to Be Used as Required)	
Low Flow Water with Low Head Loss	Magnetic flow transmitters.
Non-intrusive Mass Flow	Coriolis.
Water or Gas (non-control applications)	Magnetic flow transmitters.
Non-control Applications with Low Accuracy	Turbine flowmeters.

Process Measurement Switches

Process measurement switches shall generally have a single-pole, double-throw (Form C), snap-action contact (if deadband is not a factor) for each actuator point. Switches shall be equipped with screw or compression terminal connections for terminating field wiring. Switch set points shall be adjustable. Mercury filled switching elements shall be avoided wherever possible. Refer to Table 8-3.

Table 8-3 Process Measurement Switches

Measurement Type and Application	Project Design Basis
Temperature	Gas filled bulb elements with standard length armored capillary tubing.
Pressure	Piston, disk, or diaphragm; general static and differential; low differential/low static, low differential/high static.
Level	
Atmospheric Vessels	Point Level.
Feedwater Heaters, Enclosed Vessels, and Sumps	Moving float.
Open Tanks and Sumps	Point Level.
Specialized Applications	Capacitance, RF/admittance, ultrasonic.

Local Indicators

Dial scales (Table 8-4) shall be such that the normal operating range is in the middle third of the dial range unless designated otherwise by code.

Table 8-4 Local Indicators

Measurement Type and Application	Project Design Basis
Pressure	4-1/2-inch dial; pulsation dampener required after installation shows pulsing greater than ± 5 percent of scale.
Local	Line mounted.
Panel Mounted	Flush mounting.
When Used for Corrosive Process Fluids	Gauges to be equipped with glycerin-filled cases and diaphragm seals.

Measurement Type and Application	Project Design Basis
Code Required (such as NFPA 20)	Supplied in accordance with code requirements.
Temperature	Installed in thermowells when possible; every angle, bimetal.
Local	5-inch dial, line mounted.
Panel Mounted	Gas filled bulb elements with required length of armored capillary tubing; 4-1/2-inch dial.

Solenoid Valves

Solenoid coils shall be Class H, high temperature construction, and designed for continuous duty. Three-way solenoid valves shall be designed for universal operation so that supply air may be connected to any port. Solenoid valves used as air pilot operators shall have brass bodies with manual operators.

Control Valves

Air-operated modulating valves controlled from the PLC shall be provided with smart valve positioners with an electric analog input. Electrically actuated (motor-operated) valves, in general, will not be used for modulation. In applications where air is not available, fail-in-place is required, or if the motive force necessary to operate the valve exceeds the normal air diaphragm capability, motor-operated valves may be considered.

Position switches are to be provided on modulating valves only when required to confirm position for interlocking purposes by independent feedback. Proximity or mechanical switches may be considered for this purpose based on the deadband characteristics of the switch and installation environment (heat, vibration, etc.).

Where valve position feedback is required by the modulating loop design the position feedback transmitter shall be integral to the valve positioner.

Air-Operated Valves

Air-operated open/close valves and operators controlled from the PLC include solenoid valves and position switches. Failure modes shall be determined during detailed design.

Electrically-Operated Valves

Electrically-operated open/close/jog valves controlled from the PLC include position switches. Valves and operators required to jog (stop in undetermined intermediate positions) include position transmitters.

8.1.4 Instrument Primary (Impulse) Tubing and Piping

Instrument primary tubing and piping (impulse lines) are defined as the tubing or piping directly connected to the process, beginning at the outlet of the root valve and ending at the blowdown valve and at the connection to the instrument.

Tubing

The preferred material for impulse lines is stainless steel tubing using fittings. Instrument tubing shall be used for impulse lines and instrument hookup within instrument racks, cabinets, and/or enclosures.

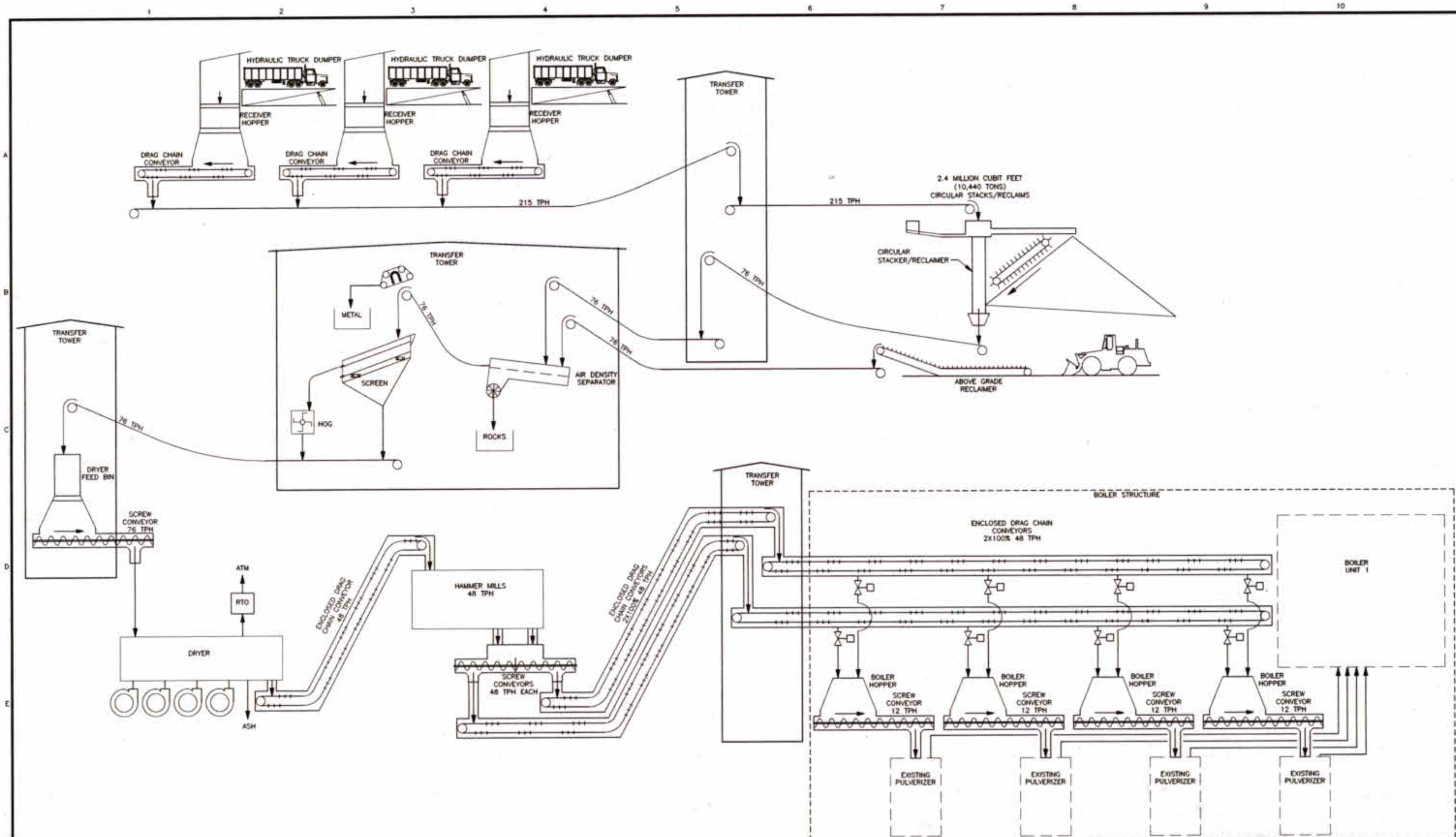
Piping

Pipe (rather than tubing) shall be used for instrument connections only when required to physically support the instrument, or where process fluids require special materials (such as seawater).

Freeze Protection

For instrument freeze protection, refer to Sections 6.3.5 and 7.1.10.

Appendix C. Process Flow Diagram



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BLACK & VEATCH
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CHECKED | DATE

ARIZONA PUBLIC SERVICE
CHOLLA UNIT 1 – BIOMASS REPOWERING
PROCESS FLOW DIAGRAM
FUEL HANDLING AND DRYING

PROJECT: 401613 | DRAWING NUMBER: SM-0001 | REV: A
CODE
AREA

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Appendix D. Equipment List

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Equipment List

Tag / GA Dwg Reference	Equipment Name	Quantity	Type	Capacity/Duty	Size	Design		Materials of Construction	Supplier	Notes
						Pressure (psig)	Temperature (°F)			
301/302/303	Truck Dumps	3								Located at 301
301/302/303	Receiving Hoppers	3								Located at 301
	Truck Scales	2								Located North of Coal Yard
	Receiving Dust Collector	1								Located at 301
304	Receiving Conveyor	1		215 tph						Located at 304
305	Transfer Tower	1								Located at 305
306A	Stockout Conveyor	1		215 tph						Located at 306A
307	Circular Stacker Reclaimer	1		215tph/76tph						Located at 307
306B	Reclaim Conveyor 1	1		76tph						Located at 306B
308	Reclaim Conveyor 2	1		76tph						Located at 308
309	Transfer Tower	1								Located at 309
	Air Density Separator/Destoner	1		76tph						Located at 309
	Magnetic Separator	1								Located at 309
	Screen	1		76tph						Located at 309
	Hog	1		76tph						Located at 309
	Dust Collector	1								Located at 309
310	Above Grade Reclaimer	1		76tph						Located at 310
311	Above Grade Reclaim Conveyor	1		76tph						Located at 311
312	Transfer Conveyor	1		76tph						Located at 312
313/314	Dryer Feed Live Bottom Bin	1		15,000 ft^3						Located at 313
315	Solid Fuel Rotary Drum Dryer	1		76tph						Located at 315
316	Drag Chain Conveyor	1		48tph						Located at 316
	Distribution Conveyors	2		48tph						Located at 317
	Hammer Mill Feed Hoppers	10		10tph						Located at 317
317	Hammer Mills	10		10tph						Located at 317
	Hammer Mill Pneumatic Collecting System	1		48tph						Located at 317
	Hammer Mill Discharge Hopper	1								Located at 317
318/319	Fuel Feed Drag Chain Conveyors	2		2x48tph						Located at 318/319
320	Transfer Tower	1								Located at 320
321/322	Fuel Feed Incline Drag Chain Conveyors	2		2x48tph						Located at 321/322
	Hopper Gates	8								Located at 323/324/325/326
323/324/325/326	Live Bottom Boiler Hoppers	4		12tph						Located at 323/324/325/326
332	Fire Water Tanks	2		420,000 gal. (ea.)	Approx. 40'(dia.) X 48' (ht.)			Carbon Steel		Located at 332.
	Fire Water Pump (Electric)	1		3,500 gpm						Located near 332. 400 HP.
	Fire Water Pump (Diesel)	1		3,500 gpm						Located near 332.
	Fire Water Jockey Pump	1								Located near 332. 1 HP.
	Carbon Dioxide Tank	1		3.5 tons				Carbon Steel		Located outdoors near 323/324/325/326.
	Carbon Dioxide Refrigeration Unit	1								Located outdoors near 323/324/325/326.
	Carbon Dioxide Vaporizer	1								Located outdoors near 323/324/325/326.
	CEMS Shelter	1								6 foot wide by 8 foot deep by 8 foot high. To be Located at Base of Unit 1 Stack.
	SNCR System	1								
	Mechanical Dust Collector	1								
	Unit 1 Corner Windbox Mods for biomass and gas	1 lot								

Appendix E. General Arrangement Drawings

REDACTED

Appendix F. One-Line Diagram

REDACTED

Appendix G. EPC Capital Cost Estimate

PGS Budgetary Estimate

APS Cholla Unit #1; Biomass Repowering

4/24/2019

SUMMARY (Rounded)

Rev. 3

Cost Type	Description	Labor Man Hrs	Wage Rate	Labor Cost	Material Cost	Subcontract Cost	Total Cost
01	Demolition	0		$0	$0	$0	$0
02	Site Work	0		$0	$0	$1,227,000	$1,227,000
03	Foundations & Concrete	111,373		$5,680,000	$2,900,000	$2,002,000	$10,582,000
04	Mat'l Handling Equipment	103,569		$5,282,000	$27,835,000	$375,000	$33,492,000
05	Steel	3,725		$190,000	$562,000	$0	$752,000
06A	Boiler & AQC Modifications	0		$0	$0	$16,200,000	$16,200,000
06B	Fire Water Tanks & Fire Prot.	0		$0	$0	$4,006,000	$4,006,000
06C	Ash System Modifications	0		$0	$0	$6,714,000	$6,714,000
07	Piping & Piping Specials	3,510		$179,000	$460,000	$0	$639,000
08	Electrical Work	18,667		$952,000	$2,223,000	$0	$3,175,000
09	I&C Work	137		$7,000	$411,000	$100,000	$518,000
10	Insulation	0		$0	$0	$60,000	$60,000
11	Painting	0		$0	$0	$0	$0
	Subtotal	240,980	$51.00	$12,290,000	$34,391,000	$30,684,000	$77,365,000
81	CM & Startup Staff			$0	$0	$5,195,000	$5,195,000
82	Scaffolding			$2,458,000	$615,000	$0	$3,073,000
83	Major Constr. Equip (cranes, etc.)	$9.00	per Direct Labor MH		$0	$2,169,000	$2,169,000
84	S/C Indirects	75%	of Direct Labor Cost		$0	$9,217,000	$9,217,000
91	Engineering	10%		$0	$0	$8,658,000	$8,658,000
92	Contingency	20%		$0	$0	$20,087,000	$20,087,000
	EPC Fee			$0	$0	$8,803,000	$8,803,000
	Project Total	240,990		$14,748,000	$35,006,000	$84,813,000	$134,567,000

$89.25 All-in Wage Rate